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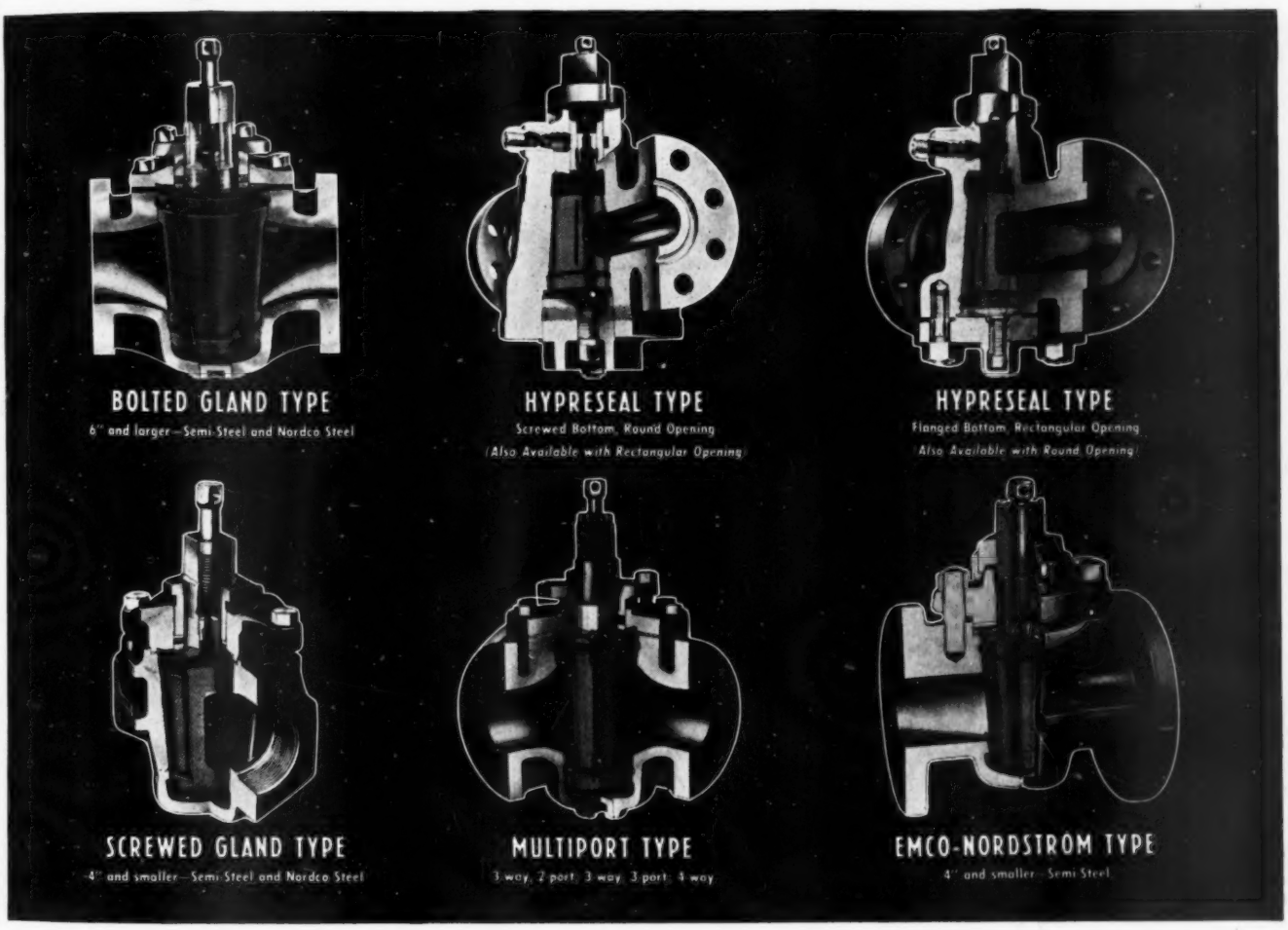

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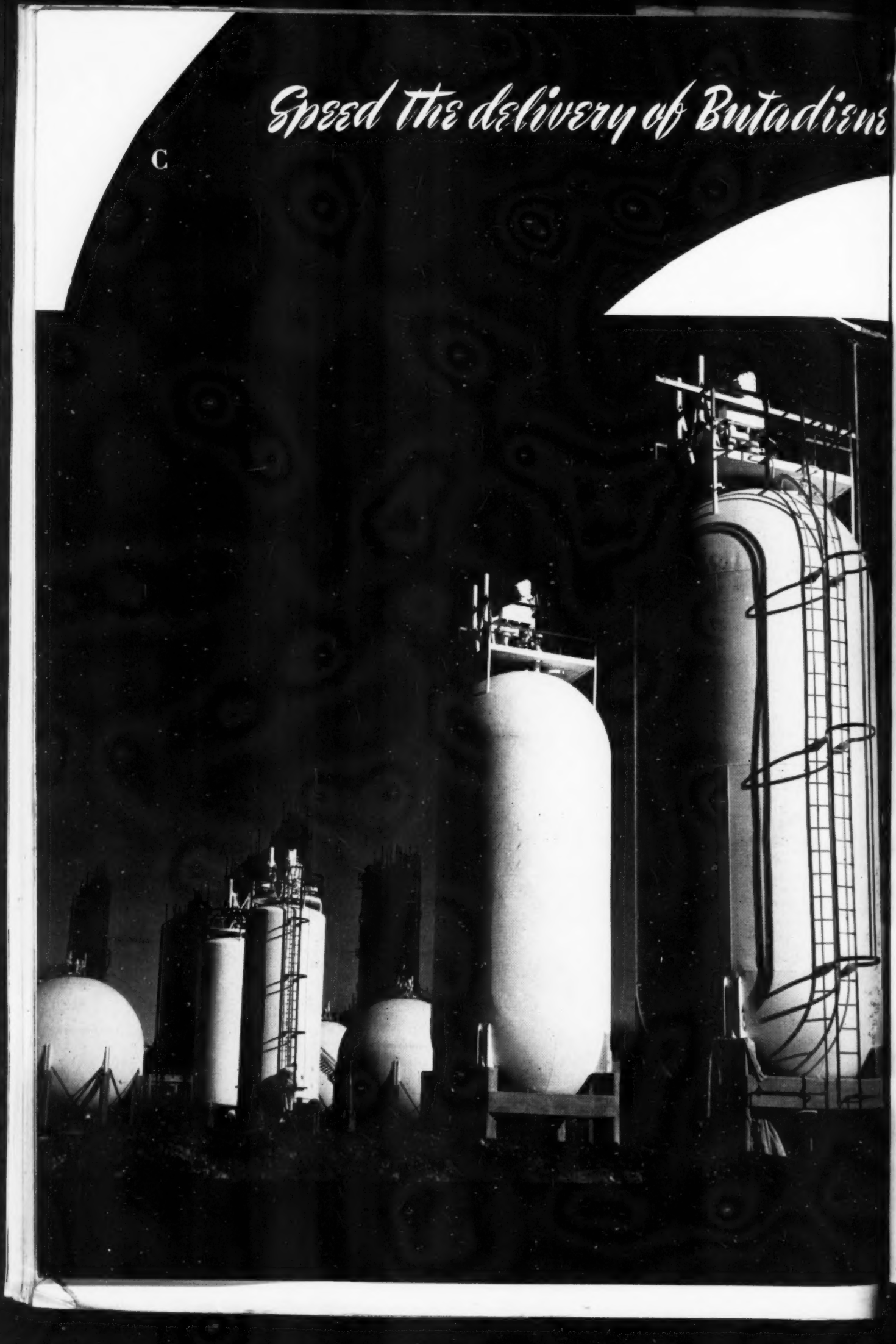
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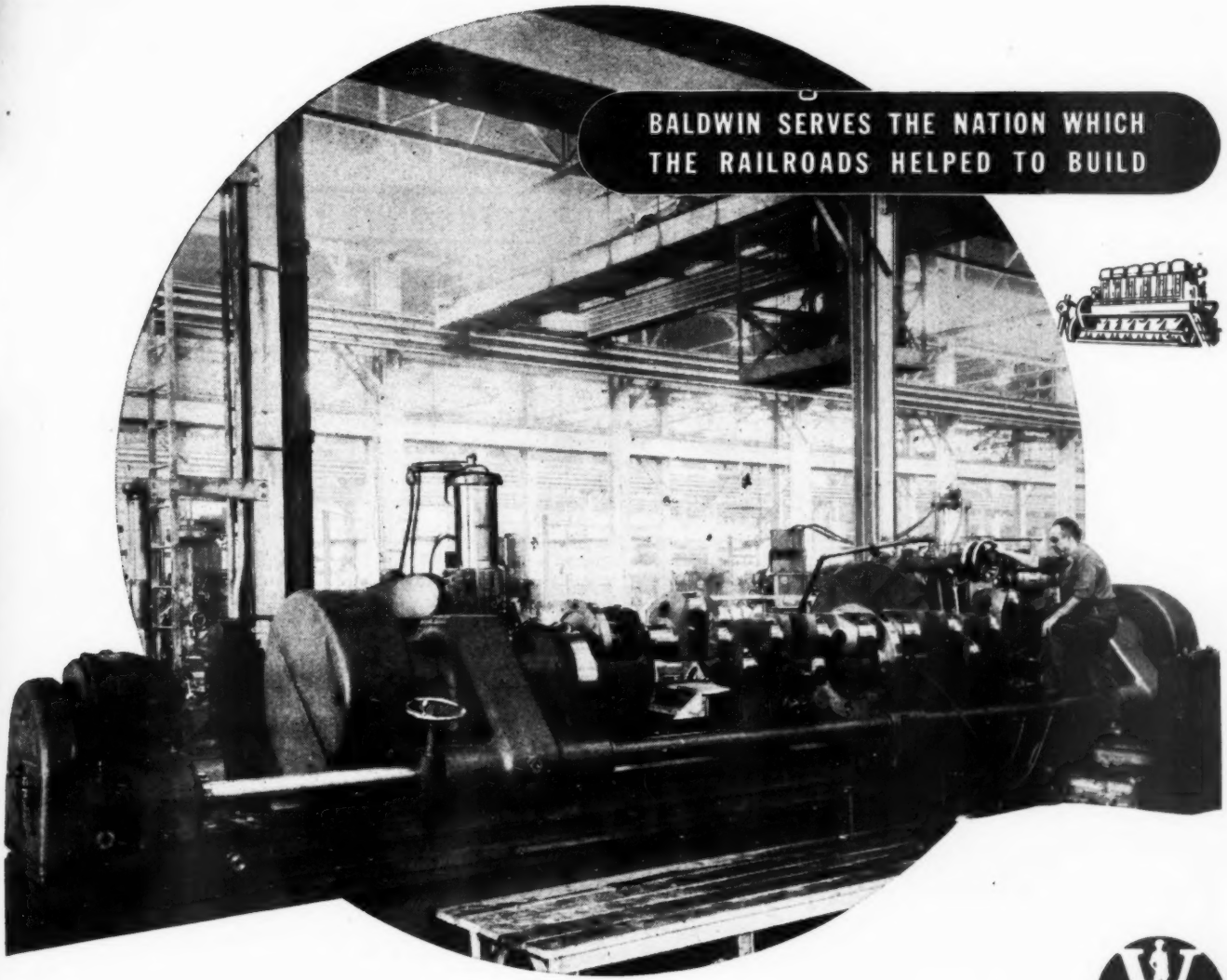

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October 3-4—American Association of Oilwell Drilling Contractors, annual meeting, Fort Worth, Texas.

October 3-5—National Safety Congress, Sherman, Morrison and La Salle hotels, Chicago, Illinois.

October 5-6—American Gas Association, Stevens Hotel, Chicago, Illinois.

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October 13—California Natural Gasoline Association, annual meeting, Biltmore Hotel, Los Angeles.

October 23-25—Independent Petroleum Association of America, annual meeting, Dallas, Texas.

November 9-10—Society of Automotive Engineers, National Fuel and Lubricants Meeting, Mayo Hotel, Tulsa, Oklahoma.

November 13-16—American Petroleum Institute annual meeting, Stevens Hotel, Chicago, Illinois.

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January 8-12—Society of Automotive Engineers, annual meeting, Book-Cadillac Hotel, Detroit, Michigan.

March 12-14, 1945—National Association of Corrosion Engineers, President Hotel, Kansas City, Missouri.

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Editorial

MANY operations are involved in the business of finding and producing crude oil, transporting it long distances by pipe line, and refining it into fuel, lubricants, and other products. Each branch of the industry is constantly developing new methods and processes. Prevailing practices are under continual modification and improvement. In this connection, the impact of war is having a telling effect on operating practice in the oil industry.

Petroleum and its products play such an important rôle in modern warfare that the demand for crude oil is now far beyond prewar needs. Special petroleum products not available in quantity before the war now are being manufactured on a scale not thought possible in so short a time. During the last two and a half years new refining facilities for the manufacture of vast quantities of petroleum products have been added to supply war needs. New products and processes have been under intensive development. Many difficult operating problems calling for quick solution have had to be overcome. The experience thus gained by such accelerated progress should not be considered lost. It can become a valuable peace-time aid by applying this experience to increasing the scope, flexibility, and efficiency of refining operations when peace comes.

During this same period in which vast new refining facilities have been added, a contrasting picture has been in the making. Drilling and producing operations were drastically curtailed by governmental orders. Blanket well-spacing regulations were imposed and the use of materials and equipment restricted. As a result, available crude oil reserves are now being drawn on at an excessive rate. Neither should this experience, however, be too heavily discounted by the industry. It should have a salutary effect on future operations, by having emphasized the benefits that accrue and the efficiency that can be attained by adopting an optimum rate of oil withdrawals.

THE Petroleum Engineer

REFERENCE ANNUAL

Standardization in Compiling Data on Exploratory Drilling And Crude Oil Reserves*

By F. H. LAHEE
Sun Oil Company

EARLY in 1943, a correspondence, which has since become voluminous, was started by the present writer on the subject of defining and classifying exploratory wells. Many geologists and petroleum engineers were consulted and opinions were freely exchanged. Many conferences have been held with groups of technical men. Among these the most helpful has been the Subcommittee on Exploration for P.A.W. District 3.[1] From the constructive criticisms and suggestions received from these several sources, we have evolved, through innumerable revisions, a classification that seems to meet with general approval. This classification is not intended to refer, individually under separate categories, to the almost numberless variations that can be cited as a result of complexities in geologic and other factors, but it is intended to cover all these varying conditions by suitable phraseology. It has been devised in the simplest form consistent with broad application to all regions. Although it is given in detail, with numerous explanatory comments, in the appendix following the present paper, we wish briefly to discuss it here.

All the different kinds of wells drilled for petroleum may be grouped either as field wells or as exploratory wells. Field wells are those located within or close to producing areas and drilled with the object of producing petroleum from the pool or pools already partly developed. Exploratory wells include those located relatively a considerable distance outside the known limits of producing areas or if within or close to the confines of a developed or partly developed pool they must be exploring for undeveloped or unknown prospects above or below this pool.

There are several kinds of field wells but we are not further concerned with them in this paper.

Exploratory wells are divisible into five groups. (See Table 1, appended). Those drilled with the object and expectation of considerably extending the limits of a partly developed pool are called *outpost wells*. Those drilled with the object of opening a new pool, i.e., a new reservoir, laterally outside the limits of a producing pool, but still on the same geologic structure as the latter, are called *new pool wildcats*. Those drilled on wholly undeveloped structures are *new field wildcats*. An exploratory hole drilled for some unknown prospects below a developed pool is a *deeper pool test*, and one drilled for some uncertain prospects above a developed pool is a *shallower pool test*.

To the average oil man such a five-fold subdivision of exploratory wells may seem unnecessarily cumbersome. He may say, why not call them all wildcats? Or why not call the "new field wildcats" simply wildcats as we have always done in the past, and call the others semi-wildcats? Why bother about the deeper pool tests and shallower pool tests in this connection; aren't these field wells any way?

In answer to these questions we can say that they and many like them have been thoroughly considered by all of us who have worked on this problem. The term "wildcat" does not embrace all types of exploratory wells. On the other hand, some holes located on structures already producing are distinctly wildcat in the sense that they involve real hazard, real danger of failure, so that we cannot properly limit this term to holes drilled on structures that have never before produced. As for the term "semi-wildcat," of this there is general disapproval because it is too vague and meaningless. Accordingly, it has been purposely eliminated.

The five-fold classification is a result of long deliberation and careful thought. It permits an easy check on the trend of the exploratory effort, whether mainly for new pays in present areas of production or for new pools on structures already located or for new pools in undeveloped regions. It facilitates an appraisal of the degree of risk being expended in this exploratory effort. And it furnishes a means of classifying discovered crude oil reserves in

[1]We are especially grateful, for construction criticisms, to G. C. Gester, A. I. Grogersen, Wm. B. Heroy, Sidney Judson, Phil Martyn, Graham B. Moody, Leonard Orynski, R. J. Schilthuis, Carleton D. Speed, E. G. Trostel, and Paul Weaver.

*Presented before American Petroleum Institute, Southwestern District Division of Production, Houston, Texas, June 13-14, 1944.

relation to the different phases of this exploratory effort. We urge, therefore, that statistics on exploratory drilling be kept according to these five subdivisions. To combine them will then be simple but the reverse would be impossible. There are three points that we wish here particularly to emphasize:

1. No terms applied to exploratory wells can be strictly cut and dried. All must be to some extent elastic due to the great variety of conditions, many of them unknown or only partly known, which may affect the classification of a well.

2. Distance from production is only one factor and this may properly vary within wide limits according to the simplicity or complexity of attendant geological conditions. In other words a hole drilled half a mile from production on a very complex geologic structure in a region characterized by lensing sands may be a more hazardous venture than a hole drilled three or four miles from production on a simple structure in a region of blanket sands.

3. Classification of exploratory wells must always include consideration of geology and consequently such classification requires geological advice. Any classification of exploratory wells that eliminates the geological factors is bound to be inadequate.

Crude Oil Reserves

Just as in the case of exploratory wells, so also with crude oil reserves there is need for standardization in compiling the data and in presenting them. Merely to state that the oil reserves of this country are so many barrels with no explanation of what the figure actually represents, leads to endless confusion and misunderstanding. But let us hasten to add that when, in an original report, a clear explanation is given and only part of this report is quoted and the explanatory material is purposely omitted, usually to save space, then the blame for causing misunderstanding rests with the editor or the reporter or the speaker, whoever he may be, who quotes. If we in the oil industry are going to clarify this situation in the minds of the public and of government officials and even in the minds of many in our own industry, we must come to a better understanding of the terminology and classification of crude oil reserves and we must agree to adopt and use a suitable classification based on this terminology.

We are not now prepared to recommend a classification of oil reserves for adoption, but we do want to suggest one for consideration toward this end. For this purpose we shall make a rough survey of the problem by contrasting some of the methods recently followed.

In the estimates published annually since 1937 by the American Petroleum Institute only "proved" or "blocked out" reserves of oil are included. These proved reserves are both drilled and undrilled. The proved drilled reserves in any pool include the oil estimated to be recoverable by the production methods already installed (whether primary or secondary) and from the area actually drilled up on the spacing pattern in vogue in that pool. The proved undrilled reserves in any pool include reserves under undrilled spacing units that are so close and so related to the drilled units that there is every reasonable probability that they will produce when drilled. Beyond these proved reserves, the A.P.I. Committee does not go.

Certain committees of the Petroleum Administration for War make estimates not only of proved oil reserves, grouping these as drilled and undrilled, but also of additional oil reserves, which they called "possible." These possible reserves include (1) oil that may be recoverable by the application of more efficient production methods (generally secondary, where only primary has been in use) and (2) oil that may be recoverable from "geologically possible extensions of underground reservoirs" considerably beyond the limits proved by wells already drilled. These two classes of reserves may be regarded as already discovered, although they have not been proved.

There are other possible reserves—we are now using the adjective with its ordinary connotation—that have not yet been discovered. These include (1) oil that may be recoverable from undeveloped pools above producing pools; (2) oil that may be recoverable from undeveloped pools below producing pools; (3) oil that may be recoverable from new pools, not yet drilled, on producing geologic structures but outside the limits of the pool or pools that have already been found on these structures, and (4) oil that may be recoverable on local geologic structures or in local geologic environments, where no oil has yet been discovered but where, because of conditions similar to those prevailing in other producing localities in the general region, there is a fair chance that new oil fields may eventually be found. All these four classes belong to undiscovered possible reserves. Note that they are all related to known local geologic structures or to known local geologic environments, which are comparable with similar producing structures or environments in the same region.

Besides the proved reserves and possible reserves, as outlined above, there are hypothetical reserves, i.e., reserves that may perhaps be present in non-producing regions underlain by sedimentary formations that yield oil in other regions. These reserves, if present, are certainly highly speculative and any attempt to estimate how large they are is purely a guess.

Finally there are substitute reserves, which include (1) oil that may be made available by chemical processing of natural gas and (2) oil that may be made available by distillation of oil shale, coal, and organic materials. These are not reserves of crude oil as such but rather of substances from which oil can be derived.

Summarizing, we have the classes of oil reserves shown in Table A.

Table 1. Classification of exploratory wells

			CLASSIFICATION WHEN DRILLING IS STARTED	CLASSIFICATION AFTER COMPLETION OR ABANDONMENT			
				SUCCESSFUL		UNSUCCESSFUL	
			A	B		C	
DRILLING FOR EXTENSION OF PARTLY DEVELOPED POOL.			1 OUTPOST	1 EXTENSION WELL (SOMETIMES A NEW POOL DISCOVERY WELL)		1 DRY OUTPOST WELL	
DRILLING FOR A NEW POOL ON A STRUCTURE OR IN A GEOLOGICAL ENVIRONMENT ALREADY PRODUCTIVE.	NEW-POOL TESTS	DRILLING WITHIN LIMITS OF AREA OF POOL. FOR NEW POOL ABOVE DEEPEST POOL.	2a SHALLOWER POOL TEST	NEW POOL DISCOVERY WELLS	2a SHALLOWER POOL DISCOVERY WELL	DRY NEW POOL TESTS	2a DRY SHALLOWER POOL TEST
		DRILLING WITHIN LIMITS OF AREA OF POOL. FOR NEW POOL BELOW DEEPEST POOL.	2b DEEPER POOL TEST		2b DEEPER POOL DISCOVERY WELL		2b DRY DEEPER POOL TEST
		DRILLING OUTSIDE LIMITS OF DEVELOPED POOLS.	2c NEW POOL WILDCAT		2c NEW POOL DISCOVERY WILDCAT		2c DRY NEW POOL WILDCAT
DRILLING FOR A NEW FIELD (I. E., ON A STRUCTURE OR IN AN ENVIRONMENT NEVER BEFORE PRODUCTIVE).			3 NEW FIELD WILDCAT	3 NEW FIELD DISCOVERY WILDCAT		3 DRY NEW FIELD WILDCAT	

TABLE A

Classification of Oil Reserves

- **Crude oil reserves**
  - **Proved reserves** — Drilled; Undrilled
  - **Possible reserves** — Discovered; Undiscovered
  - **Hypothetical reserves**
  - **Substitute reserves**

If in every estimate of reserves the author would clearly state to which of these categories his figures apply, there would be much less confusion. The trouble is that one person may be talking of proved reserves only; another of proved plus possible discovered reserves; another of proved reserves plus all possible reserves, both discovered and undiscovered; another of all groups of crude oil reserves together, and sometimes, without too precise definition, substitute reserves and crude oil reserves may be thrown into one huge estimate, and then indeed the future supply becomes magnificent. There is no necessity for commenting further on this subject here.

Briefly, then, in order to promote a better general understanding of the methods and the results of the exploratory effort of the industry, we urge (1) adoption of the "Classification of Exploratory Drilling" as presented in the appendix accompanying this paper and (2) study of the "Classification of Oil Reserves," as suggested above and outlined in Table A, with the thought that this, too, may serve a useful purpose toward the end desired, provided it meets with approval.

Appendix

Classification of Exploratory Drilling for Petroleum*

A. **Definitions.** The definitions given in this paper are for the purpose of reporting exploratory drilling, and are not to be construed as legal definitions.

1. **Petroleum defined.** For statistical purposes, as discussed herebelow, petroleum is defined as including crude oil, natural hydrocarbon gas, and the condensate content of natural gas, wherever these occur under natural conditions.

2. **Occurrence of petroleum.** (a) A *pool* as used in the following discussion is an underground accumulation of petroleum in a single and separate natural reservoir (usually a porous sandstone or limestone). It is characterized by a single natural pressure system so that production of petroleum from one part of the pool will affect the reservoir pressure throughout its extent. In all directions a pool is so bounded by geologic barriers, such as impermeable strata, geologic structural conditons, and water in the rock formations, that it is effectively separated from any other pools that may be present in the same district, or on the same geologic structure. (b) A *field* may be a single pool, or it may consist of two or more pools, all on, or related to, the same geologic structure. Where there is more than one pool in the same field, the several pools are separated from one another through geologic causes such as synclinal conditions, faulting, pinching out of reservoir beds, and changes in porosity and permeability. The pools may occur at several horizons or different geologic age, separated by relatively impervious strata, and in such cases they may directly or only partly overlap one another in a horizontal sense or they may not overlap at all.

Comment. The terms "pool" and "field" are applied herebelow only where they are capable of producing oil or gas in substantial quantities, which in most cases means in commercial quantities. These terms are not intended to cover slight accumulations from which nothing but very small showings can be obtained. See comments on "Discovery" under 5 (c).

While a field may include several pools that, by definition, must all be on or related to the same geologic structure, the reverse may not be true. In other words, all the pools on one major structure do not necessarily constitute one field. If the structure is large, several fields may be located on it.

3. **Classification of drilling.** (a) *Development drilling*, in the petroleum industry, is the drilling of wells within, or close to, the limits of a producing (or producible) pool, as these limits are known at the time of this drilling, the object being to complete such wells in the "pay horizon" (sand, lime, etc.) of the pool.

Comment: The word "producible" is added in parentheses here and elsewhere in this report to cover the case of a pool that temporarily may not be producing because its well or wells are shut in.

Development drilling is mentioned in this paper mainly for contrast with exploratory drilling.

(b) *Exploratory drilling* is (1) the drilling of wells relatively a considerable distance outside the limits of development, or developing, pools as these limits are known at the time of such drilling or (2) the drilling of wells within the then known limits of a pool with the object of searching for new producible horizons above or below the producing (or producible) horizon of the pool or, if there are two or more superposed pools in the field, above or below the producing (or producible) horizon of the deepest pool penetrated by this well.

Comment: For a discussion of this subject see 4 (b) (3).

4. **Classification of wells at time of commencement of drilling.** (a) Under the head of development drilling may be listed field wells.

A *field well* is a well drilled with the object of further exploiting the pay horizon of a pool within the area that has already been essentially proved for production in this pool. Such a well may be inside the pool as already outlined by producing (or producible) wells or it may be a relatively short distance outside these limits.

Comments: Under this definition an edge well, i.e., a well knowingly drilled close to the recognized productive boundary of a pool, is a field well, and this is true whether this edge well is completed as a producer (within the pool) or is abandoned as a dry hole (just outside the boundary of the pool). After discovery of a new pool or a new field, the second well and subsequent wells should all be called field wells if they meet the requirements of the definition as above stated.

"Field well" may be applied to a well within a field consisting of a single pool or in a field consisting of two or more pools but in the latter case the objective must be the producing horizon of that pool within the boundaries of which, or close to the boundaries of which, this well is located.

On a structure of moderate relief, where the producing horizon blankets the entire structure and where through subsurface mapping the contours on this horizon can be mapped with a fair degree of correctness, a hole drilled on an undeveloped part of the structure but considerably above edgewater level, may be called a field well because its chances of production are very good. Note that in this case the underground conditions are pretty definitely known as contrasted with what is known affecting an outpost well (described later).

(b) Under the heading of exploratory drilling we may list these classes of wells: wildcat wells (including new field wildcats and new pool wildcats), outpost wells, deeper pool tests, and shallower pool tests.

(1) A *wildcat well* (or simply wildcat) is a well located relatively a considerable distance outside the limits of producing (or producible) pools as these limits are known at the time of its drilling. A *new field wildcat* is a hole drilled on a geologic structure or in a geologic environment where petroleum has not yet been discovered. A *new pool wildcat* is a hole drilled on a structure or in a geologic environment where other pools have been found but where the complexities in the underground geologic conditions are so great that searching for a new pool is very hazardous. As suggested in these names, the objective of a new field wildcat is discovery of a new field and the objective of a new pool wildcat is discovery of a

*The following text is Part II of F. H. Lahee's "Classification of Exploratory Drilling and Statistics for 1943," published in the Bulletin of the American Association of Petroleum Geologists in June, 1944. It was accepted for general use by the Petroleum Administration for War and the Petroleum Industry War Council on May 2, 1944.

new pool in a field already discovered (see "Comments" following the next paragraph).

(2) An *outpost well* (or outpost) is a hole drilled with the thought that it will probably extend, by a considerable distance, a pool already partly developed. Its original objective is the producing horizon of this pool, although it may be completed or abandoned at a higher or at a lower stratigraphic horizon. It is far enough from the limits of the pool, as known at the time when its drilling is started, to make its outcome uncertain but it is not far enough from these limits to be designated a wildcat. If it is successful in its original object it will add materially to the productive area of the pool. It may be dry.

Comments. As we have pointed out before, the element of risk of failure to find oil is an important factor in classifying wildcats and outposts. Therefore, where geological conditions are simple and easy to anticipate and where, for this reason, a well is likely to find production, the distance of a wildcat measured from the known limits of the nearest pool (not from any other drilling well), will be greater than where geological conditions are complicated and failure is not unlikely. Where pools are known to be large and geological conditions simple, a hole located two or three miles from the nearest productive area may be classed as an outpost. Where conditions are complicated as on a salt dome or in an area characterized by faulting or by lensing or shaling sands, a hole drilled just outside the known actual edge of a pool and on the same structure as that on which this pool is located is essentially a wildcat, for it is exploring for unknown possibilities under complex geological conditions. On the other hand, if a hole is drilled along strike several locations from production on a salt dome, it may better be called an outpost, unless faulting is believed too great to diminish the chance of extending the known producing area in that direction.

Obviously, the definition of wildcat or outpost must be applied when a hole is started and not after its completion. For example, nothing learned during the drilling of a wildcat nor after its completion or abandonment can alter the degree of risk taken in the original venture of locating and drilling the hole. If two holes are started as wildcats in the same area, they are still wildcats even if one of them happens to discover production before the other is completed.

(3) A *deeper pool test* is a well located within the known limits of a pool and drilled with the object of searching for new producible horizons below the producing (or producible) horizon of the pool or if there are two or more overlapping pools below the producing (or producible) horizon of the deepest pool penetrated by this well.

Comments: In nearly all cases "below," as used in this definition, means both stratigraphically below and at a greater depth but under very rare conditions, such as overthrust faulting, the producing horizon of the pool might be stratigraphically older, though shallower, than the deeper prospects sought in the deeper pool test.

Under certain conditions of complicated geology, within a field that includes two or more pools at different stratigraphic levels and not superposed one above another, deeper pool test may be applied to a hole located within the producing area of a higher pool but considerably outside the producing area of a lower pool if the objective of this well is below the pay horizon of the pool within which it is located. For this classification such a hole should be far enough from the edge of the deeper pool to be designated a wildcat if there were no higher pool.

There has been much question as to how to discriminate between (1) a well drilled from the surface with the object of searching for unknown prospects below the deepest known pay horizon penetrated by the well and finally completed as the discovery well of a new deep pool or abandoned at its total depth as a dry deeper pool test; (2) a well similarly drilled but after failing to discover deep oil plugged back and completed in the pay horizon of the deepest pool within the confines of which it was located, and (3) a field well that after producing for some time (days, months, or years) from the known pay of the pool, has then been deepened to explore underlying unknown possibilities. In order to simplify the statistical study of these three varieties of hole, we shall list all as deeper pool tests but in each case we shall assign as exploratory footage only the footage below the pay horizon of the deepest previously known pool penetrated by this well.

(4) A *shallower pool test* is a well located within the known limits of a pool and drilled with the object of searching for new producible horizons above the producing (or producible) horizon of the pool or, if there are two or more overlapping pools at the site of the well, above the deepest of these pools.

Comments: Wildcats, both those exploring for new fields and those exploring for new pools, are holes drilled considerably outside the limits of producing areas in a lateral sense, that is, as would be obvious on a map. On the other hand, deeper pool tests and shallower pool tests are exploratory in a vertical sense since they are drilled to search for deeper or shallower new pools respectively above or below a known and partly or wholly developed pool. It is true that a shallower pool test will penetrate a stratigraphic section at least partially known, but it will definitely be exploring for petroleum and often for structure. Our reason for relating

Table 2. Tabulation of statistics on exploratory wells

STATE OR DISTRICT	1 OUTPOST WELLS					2 NEW-POOL TESTS															3 NEW-FIELD WILDCATS					TOTAL EXPLORATORY WELLS DISTRICT OR STATE				
						2a SHALLOWER-POOL TESTS					2b DEEPER-POOL TESTS					2c NEW-POOL WILDCATS														
	SUCCESSFUL			FAILURE	TOTAL	SUCCESSFUL			FAILURE	TOTAL	SUCCESSFUL			FAILURE	TOTAL	SUCCESSFUL			FAILURE	TOTAL	SUCCESSFUL			FAILURE	TOTAL	SUCCESSFUL			FAILURE	TOTAL
	OIL	GAS	COND.*			OIL	GAS	COND.*			OIL	GAS	COND.*			OIL	GAS	COND.*			OIL	GAS	COND.*			OIL	GAS	COND.*		
TOTALS																														
									TOTAL NEW-POOL TESTS (2a+2b+2c) →																						

*COND. = CONDENSATE OR DISTILLATE

both the shallower pool and deeper pool tests to the deepest producing horizon in an area of two or more superposed pools is that this greatly simplifies the definition. It is much better to do this than to attempt to discriminate between such tests which might be exploring at various levels where there are several overlapping pools in one field.

5. **Results of Drilling.** As results of drilling we may designate wells as *dry holes*, as *extension wells*, or as *discovery wells*.

(a) Any hole, even a well drilled within the known boundaries of a pool as a field well, may be abandoned as *dry*. However, the chances are that field wells will produce, or be producible, and although the risk is greater outpost wells have a fair chance of success but wildcats, according to statistics, have less than one chance in five or six of discovering oil or gas "in substantial quantities."

(b) Any well that is located as an outpost well or as a wildcat will be classified as an extension well (as a result of its drilling), if it extends the productive (or producible) area of a pool (see Table 1) but this classification cannot logically be applied until after the fact is demonstrated and such demonstration may require the drilling of several intermediate wells.

(c) Any wildcat, outpost, deeper pool test, or shallower pool test that discovers a new pool of petroleum,* is a *discovery well*.

Comments: Discovery, then, as applied to oil and gas is the finding of a previously unknown or unproved pool of petroleum. For the first pool on a geologic structure we may speak of discovery of a pool or discovery of a field for this first pool may also be called a field but where there are several pools in one field, there can be only one field-discovery well on this structure, i.e., the well that was completed as a producer in the first pool found. Thereafter the wells discovering new pools on this same structure are pool-discovery wells; they are not field-discovery wells.

Sometimes a wildcat, drilled some distance from production, is at first erroneously credited with discovery of a new pool. Subsequently, through the drilling of additional wells it is shown to be an extension well of a pool previously known. Such a well, although it must obviously be removed from the category of discovery wells when the fact is proved, is nevertheless due full credit as a wildcat based on factors of distance and risk at the time its drilling was undertaken.

It frequently happens that the discovery well on a structure or a well drilled subsequently in the course of development of the field penetrates more than one horizon that is capable of producing oil or gas in substantial quantities. Generally the well will be completed in only a single horizon. If the well is the discovery well on the field, the horizon in which it is completed thus becomes the initial pool of the field. Other potentially productive horizons penetrated either above or below the horizon in which the well was completed would not be considered technically as "discovered" until a well has been completed as a producer from each of them. Even if the evidence of the presence of petroleum in such a horizon were virtually conclusive, a well producing or so completed that it could produce from this horizon would be required to constitute a new discovery. This distinction is essential even though from the interpretation of electrical logs, from core samples, and even from drillstem tests, it may seem almost certain that the horizon is capable of production. If the discovery well of a field were completed and producible from two horizons, such a dual completion would, of course, be the discovery well of two pools. The discovery well of a new pool or pay horizon is, accordingly, not necessarily the first well that penetrated the pay horizon and found evidence of petroleum in it but the first well to produce substantial quantities of oil or gas from it.

(d) The *date of discovery* of a pool is the date on which the discovery well of the pool is completed as a producer of petroleum. For a field this would be the date of discovery of the first pool in the field. If the first well completed in a pool happened to be in the gas cap of an oil pool, this would still be the discovery well of the pool as a whole including both gas and oil.

B. **Statistics on exploratory drilling.** In order that the statistics of exploratory drilling may be as consistent as possible between different areas and in order that those in successive years may be as nearly comparable as possible, the foregoing definitions have been suggested for general adoption. In applying these definitions there is bound to be some question in a few borderline cases but for the most part classification should be made without difficulty.

Attention is again called to the differences between sections 4 and 5 in the foregoing. Bear in mind that preliminary classification is based on the degree of risk of failure as estimated when drilling of the hole is commenced, and this risk is contingent on how much is known of underground geological conditions when drilling is started. Also remember that preliminary classification of a well, made before the well is completed, cannot logically include reference to discovery or extension. Thus, classifications under Column A in Table 1 are fixed and must not be changed. On the other hand, classifications under Column B may have to be changed as more information becomes available.

In compiling statistics for study of both the exploratory effort and the results of this effort, all five types of exploratory holes should be separately treated. We refer to the types labelled 1, 2a, 2b, 2c, and 3 in Table 1. Unless the data are thus broken down misinterpretations of the tabulated statistics are inevitable. However, where the object is merely to classify results, as for example newly discovered reserves, the data may be satisfactorily grouped under heading 1, 2, and 3, all three subclasses of 2 being combined or they may be grouped under 1, 2a + 2b, and 2c + 3.

Table 1 is a summary presentation of the classifications described in the foregoing pages. To some extent it is briefly explanatory. By following its designations statistics can be recorded in several ways. Table 2 is a suggestion for tabulating statistics. In it the main columns correspond to Groups 1, 2a, 2b, 2c, and 3 in Table 1. Under each of these are three subheadings, successful, failure, and total. The first two could be headed producer and dry, if preferred. Under successful the kind of producer (oil, gas, or condensate) is indicated and in this column under each major heading it may be shown whether the producer was a discovery well or an extension well (as proved by the drilling) by the letters 'd' and 'c,' respectively, against the recorded data. As for these data, the number of holes or the exploratory footage or both can be shown.

To each wildcat, shallower pool test, and outpost well, its total footage is to be assigned and listed but, as above explained, each deeper pool test is to be credited with only that footage drilled below the pay horizon of the deepest pool within the limits of which it was drilled. In no case should footage penetrated in sidetracking or in redrilling of a lost hole be included in the total footage of any hole.

A hole temporarily abandoned should not be listed in one year's record and then again in succeeding years each time it is drilled a little deeper. As far as can be determined, it should be listed only when it has been permanently abandoned. Where after a long lapse of time a hole recorded as permanently abandoned is cleaned out and drilled deeper, it should be so designated as an exception in the later listing and only the additional footage drilled should be assigned to it as of the year during which it was thus deepened.

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*See foregoing definitions of pool and petroleum.

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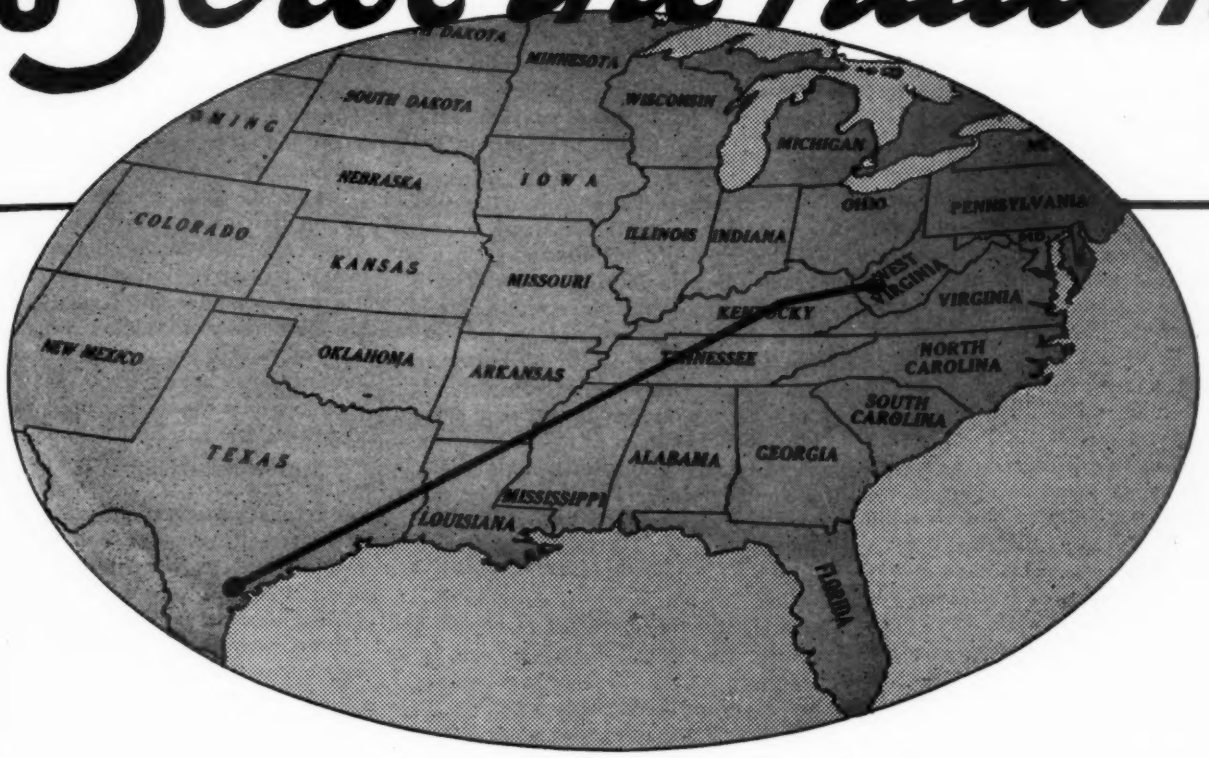

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Blowouts—Causes and Prevention*

By MADDEN T. WORKS, *Chief Engineer*
Cameron Iron Works, Inc.

INTRODUCTION. When it was suggested to the API Southwestern District Topical Committee on Drilling Practice that a study be devoted to the subject of this paper, it was realized that the industry was already in possession of rather extensive information as to both the cause and prevention of blowouts, this information having been disseminated not only through the medium of several excellent technical papers on the subject (See bibliography) but also through the efforts of service organizations and manufacturers which supply drilling muds, wellhead fittings, and other well control devices. However, in spite of considerable general knowledge on the subject, uncontrolled blowouts are continuing to occur. There are no accurate records available, so it cannot be said whether the percentage of occurrence is increasing or decreasing, but the fact that there were 30 serious blowouts in the Gulf Coast of Louisiana and Texas during last year (1943) is sufficient cause for reviewing the situation and bringing as much concerted effort as possible to bear in an effort to reduce this vast physical and economic loss.

It is recognized that the problem of well control is extremely wide in scope and has many ramifications. For this reason, it is thought that the problem is essentially one for group study, and that a series of papers, each devoted to a particular phase of the problem, will be required to completely cover the subject. The various operating companies have been most cooperative in exchanging ideas and information. However, to date there has been no adequate machinery set up for keeping all information on a current basis, and for disseminating new ideas and methods throughout the industry. It is believed, and suggested, that if arrangements were made whereby a technical group could receive complete and detailed information on a large number of previous blowouts and also on each new blowout which might occur, that in the course of time and by means of periodic reports, much of value could be accomplished. In collecting data prior to the preparation of this paper, the Topical Committee sent out a questionnaire to a group of operators who had had blowouts in the recent past. The cooperation offered by the operators replying to the questionnaire was quite gratifying and, although there were an insufficient number of wells reported on to permit any general conclusions, it could be readily seen that the extension of such a reporting system would be of inestimable value.

As stated previously, it is not feasible to attempt to cover the entire subject of the causes of blowouts and their prevention in a single paper. Also, as mentioned, a more extensive study should be instituted before attempting to offer any concrete solutions. However, since the questionnaire which was sent out gave definite indication that many blowouts can be traced to bad practices, the Topical Committee believes that a preliminary paper which would be, primarily, a review of the situation would aid in focusing the attention of the industry on certain phases of the problem which, it appears, may not have had enough attention directed to them recently. This paper, therefore, will attempt to restate the known causes for blowouts and make suggestions for an educational program, for it is certain that nothing can be accomplished towards reducing the number of blowouts unless the entire operating personnel of the industry, from top to bottom, is made thoroughly conversant with the problem. This paper will be devoted to the problem of blowouts on drilling wells only, as loss on control of producing wells is an entirely different phase of the subject.

When entering into the study of any problem, it is always good practice to first make a clear statement of the problem. In the case of blowouts it is relatively easy to make a list of possible causes. Also, it is relatively easy for one "skilled in the art" to set opposite each cause preventive measures which, if followed, would preclude the occurrence of blowouts from that cause. Upon doing this, one may easily say that the problem is quite simple, and that there is no reason for there ever being any more blowouts. This would be the correct answer if it were not for a very important factor, and that is that wells are drilled by men and, consequently, the human element is likely to upset the nicest of plans and calculations. It is true that there are a few possible causes of blowouts which may properly be termed "Acts of God" but, fortunately, these causes are few in number and their probability of occurring is quite slight. Since there is admittedly nothing, so far as is known, that can be done about a situation such as storm or lightning destroying surface control equipment, it would be rather pointless to dwell upon it to any extent here. However, it might be worth while to mention that certain other causes which, while they cannot truly be termed "Acts of God," approach that classification in that blowouts may occur when these conditions are encountered for the reason that stresses may be placed upon the control equipment in excess of even the most conservative allowance for factors of safety. For example, abnormal pressures may be encountered of a magnitude which cannot be coped with by even the most carefully selected equipment. Another eventuality which falls in the same category is the sudden loss of returns in cavities, crevices, etc. However, if adequate control equipment has been provided in the first place, a wild well will not result from lost returns unless the sudden loss of the mud column permits an uprush of sufficient violence to damage the pipe or control equipment. Of course, when either zones of abnormal pressure or caverns underlying gas sands are known to exist in a given area, trouble resulting from these causes cannot conceivably be passed off as being "Acts of God."

There is one other cause of loss of control on drilling wells that is extremely difficult to classify, and that is mechanical failure. Of course, it is not difficult to classify mechanical failures which are brought about by the equipment being called upon to perform tasks for which it was not designed, but the failure of carefully selected and pretested equipment apparently in a good state of repair is another matter. Fortunately, failures of this nature are extremely rare. To sum up the above remarks, it might be said that while blowouts due to so-called "Acts of God" can and do occur, the probability of their occurrence is extremely slight and the tendency, which many of you may have noted, of wanting to place *all* blowouts in this category should be studiously avoided.

Now, if we return to the list of blowout causes mentioned above, it is readily apparent that the responsibility for permitting these causes to exist on any operation may be assigned to the two main divisions of operating personnel. That is, there is a group of causes over which management alone has control, and there is the other group of causes which fall under the control of the per-

(Continued on Page 46)

*Presented before American Petroleum Institute Southwestern District Division of Production, Houston, Texas, June 13-14, 1944.

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(Continued from Page 42)

sonnel actually executing the work in the field. That is, the list of causes may be divided and tabulated in the following manner:

I. Causes under control of management.
- a. Use of improper drilling mud.
- b. Failure to provide an ample reserve supply of mud.
- c. Inadequate mud pumping equipment.
- d. An inadequate casing program.
- e. Inadequate, obsolete, or worn out control equipment.
- f. Lack of periodic inspection of vital equipment and failure to authorize necessary repairs.
- g. Failure to give complete and concise instructions to subordinates, and insufficient supervision.
- h. Lack of a practical educational and safety program.

II. Causes under control of subordinate personnel.
- a. Drilling gas sands too fast.
- b. Pulling pipe off bottom to rapidly.
- c. Balling up the bit or drill collar by crowding in sticky formations.
- d. Using too large a diameter drill collar.
- e. Pulling pipe out of the hole before the mud is in proper condition.
- f. Failure to run fill-up pump frequently while pulling pipe from hole.
- g. Use of low pressure fittings in high pressure control manifolds.
- h. Procrastination in making rig repairs.
- i. Continuing to drill or circulate during a heavy rain.
- j. Failure to maintain the reserve mud supply in condition for use.
- k. Lack of general vigilance for the unmistakable signs of gas.
- l. Failure to obey specific instructions.

There is nothing new in the above list except, possibly, the classification into which the causes have been placed.

It is fortunate that the management of most operating companies makes considerable effort towards observing the best practices known. However, even the best of them seem to occasionally slip into bad practices, possibly due to overconfidence resulting from long periods of trouble free operation. Then, there is a certain class of operators, which is in the minority, who seem to insist on multiplying the hazards of well drilling by continuously indulging in careless and imprudent practices. It is feared that management of those companies in the latter category cannot in most cases offer the excuse of either oversight or ignorance, and the only other excuse that may be offered is one of economics. It is the stated purpose of this paper to suggest an educational program that might help make the entire industry blowout conscious. However, it is extremely difficult to offer concrete suggestions as to a program that will successfully reach not only the backsliding good operators, but also the operators who indulge in bad practices as a result of false economy.

Since there seems to be no effective way of forcibly drawing the negligent operators' attention to the fact that careful and prudent practices are the cheapest insurance that can be obtained, advertising and educational measures both verbal and otherwise must be relied upon. The insurance companies have done an extremely good selling job in that no one, whatever his business policy might be, will allow his life insurance to lapse except under the direst circumstances. Therefore, it appears that the oil industry may have a selling job to do in inducing the "black sheep" to always carry plenty of insurance in the form of the best practices. Of course, many operators can exercise considerable control by specific attention in their drilling contracts to the various causes of blowouts. Also, there is the expedient of controlling drilling practices by legislation. However, neither one of these methods can be entirely effective, and it certainly goes without saying that the less legislation involved the better, and this step should be taken only as a last resort. Therefore, it appears that the best plan is simply for the good operators to devote some time to selling the not so good operators on the idea that the relatively small cost entailed in following the best practices is more than amply repaid from the standpoint of protection. Such a program should serve the further purpose of tending to keep the better operators "on their toes" and blowout conscious at all times.

In reviewing the list of causes of blowouts which come under the control of management, it can be shown that there is actually very little cost involved in circumventing any of the causes. Let us look at each of them in detail.

I-a. Use of improper drilling mud. What proper mud is, of course, varies for different conditions. Probably the best way of being reasonably sure that the mud will be proper for the given set of conditions is to employ a competent mud engineer and make it his responsibility to see to it that the drilling mud is at all times in proper condition. The cost of a mud engineer's salary plus the cost of the necessary chemicals, weighting materials, etc., over a period of years will be almost insignificant in comparison with the cost of a single serious blowout. Many operators shy away from such a program for the reason that they have heard tales of extremely high mud costs on certain wells where the mud was the responsibility of the mud engineer. However, they overlook the fact that, in most instances, the cost was entailed by extremely difficult operating conditions and that if the money had not been spent on mud control a much larger sum would probably have been spent on getting out of serious blowout trouble. Also, records of major companies positively show that mud costs are actually less when the mud is under the control of a competent mud engineer rather than under the control of the drilling crews, for the reason that one untrained in the art of mud treatment almost invariably overtreats, thus causing a wastage of treating materials. Therefore, a carefully planned and engineered mud control program should be considered as good insurance purchased at a bargain price.

I-b. Failure to provide an ample reserve supply of mud. This cause of blowouts is closely allied to the ones just discussed. As stated by Carpenter[8]: "In most instances, inferior drilling fluid is transferred to the reserve pits; and no effort is made, in all fields, to recondition it unless circulation is lost, a blowout occurs, or replacement of drilling fluid in the hole becomes necessary because of gas-cutting or the precipitating action of salt water. When additional mud is required in a hurry it is usually necessary to stop drilling while reconditioning the drilling fluid in the reserve pit or awaiting purchase and delivery of commercial clays with which to make new drilling fluid. Therefore, as a matter of safety and economy it is important to have in reserve an ample supply of drilling fluid of the proper weight and consistency. When drilling is done in high-pressure gas zones the reserve supply should at least be equal to the total volume of the drilled hole." This point is also noted by Vietti and Levy[3] who state: "Failure to have an adequate reserve mud supply, or supply of commercial material, is inexcusable in areas where mud losses or gas sands may be reasonably expected." Note that these remarks may be combined and paraphrased to the effect that the inexcusable lack of an ample reserve mud supply is false economy.

I-c. Inadequate mud pumping equipment. Even the most carefully planned mud program and the strictest attention to the reserve supply will be of little avail if the mud pumping equipment has inadequate capacity and pressure to meet any emergency since all

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the functions of drilling fluid, except that of suppressing formation pressure, are performed by circulation. In order to avoid a circulation failure at a crucial moment, it is essential that two slush pumps in good repair, and supplied with ample power, be available. Also, it is essential that the pumps be manifolded in such a way that they may be instantly compounded or paralleled, thus enabling the driller to increase the pressure and/or rate of circulation at will.

The three points that have been discussed above may be summed up with the statement that an ample supply of drilling mud of the proper consistency with adequate circulation under all conditions is the first line of defense against blowouts, and no operator can expect to protect his investment without strict attention to this phase of well drilling.

I-d. An inadequate casing program. The definition of an adequate casing program varies for different areas and conditions in the same way that the definition of a proper drilling mud varies. However, except on wildcat wells, this is a phase of the business which is quite closely controlled by the regulatory bodies of the various states. Therefore, it is only on exploratory wells that an operator has much chance to go too far wrong on a casing program. Since it is a known fact that the majority of blowouts occur on wildcats, prudent operators will devote considerable care to the selection of a casing plan. As a matter of fact, it is highly advisable to have an alternate plan also available for, in drilling unknown formations, unlooked for situations may arise which would necessitate a change in the pipe program at a moment's notice. In view of the rather elementary fact that a good casing program would tend to offset the increased hazard of exploratory drilling, it is rather surprising to discover that in a substantial percentage of blowouts on wildcat wells the reason for ultimate loss of control lies in an inadequate casing program. It appears that the only advance program that some operators set up is to set a few hundred feet of relatively large pipe and then drill on down in hopes that no trouble will be encountered. This is a curious attitude—particularly when viewed from the standpoint that the only reason for drilling the well is to hope that oil or gas will be discovered, preferably in copious quantities and at a reasonable pressure. One wonders about the fellow who set less than 500 ft. of 13⅜-in. casing and then drilled on without much trouble until gas sands were encountered at around 5000 ft. From there on the mud engineer had the nice problem of keeping the mud heavy enough to hold back the pressure and yet light enough not to be lost to the formations. Finally, at around 6000 ft., this fine state of balance got out of hand and it was necessary to shut in the well with the blowout preventers. In less time than it takes to tell it the well had cratered due to a blow around the surface pipe, and a $150,000 investment in drilling rig and well bore was no more. Would this fellow be hard to convince that a few more dollars spent on surface pipe, and possibly a protection string, would have been cheap insurance on a substantial investment?

I-e. Inadequate, obsolete or worn-out control equipment. According to the questionnaire, 66 per cent of the operators reporting believe that drilling crews in general do not analyze the basic causes of blowouts, or exercise sufficient diligence, and depend unduly upon equipment to control a situation before it gets out of hand. This is interesting, for it is the positive knowledge of the author that much of the control equipment in everyday use in the field either is entirely too light for the depth being drilled or is in such a state that it could not possibly function. It cannot be understood why some operators, even though they would not consider using a frayed drilling line or worn drill pipe, will be entirely satisfied with anything that is called "blowout preventer" regardless of its adequacy, age, or condition. The attitude seems to be that since the law requires that wells be equipped with a blowout preventer, all that is needed is a piece of equipment which is dignified by that name. When this attitude is balanced against the dependence of drilling crews on control equipment keeping them out of trouble, one can readily see why many blowouts occur which could have been prevented by greater attention to the control equipment detail.

Another point that often escapes proper attention from management is the auxiliary equipment, such as fittings, flange bolts, etc., required to hook up the control equipment. The effectiveness of the best control equipment can be completely nullified by the use of such items as cast iron fittings and undersize carbon steel flange bolts in assembling high pressure connections. It seems that there is no effective way of *forcing* all operators to either use or properly install good control devices as both contractual treatment and state regulations fall short of the desired end. Therefore, here again, an educational program appears to be indicated in order to convince backward operators that a relatively small investment in control equipment will offer a protection that cannot otherwise be obtained.

I-f. Lack of periodic inspection of vital equipment, and failure to authorize necessary repairs. This phase of the topic is very closely allied to that just discussed, and it is one that apparently has never received the attention it deserves. One cannot spend much time around a shop that is engaged in overhauling and repairing drilling control equipment without gaining the distinct impression that much of the equipment is in considerably worse condition than the owner realized. It is unfortunate that very few of the working parts of most control devices are exposed to view, and it is often surprising the deplorable conditions in which one will often find the inside of a blowout preventer or valve, while the outside may be in beautiful condition—even to the extent of a fresh coat of paint. Therefore, the conscientious operator should not overlook the importance of thorough inspection of all vital equipment at frequent intervals. The most popular types of modern control equipment are of extremely rugged construction but, under the rough usage to which they are subjected, even the best devices cannot be expected to remain in proper working condition indefinitely without some attention. The other point that should be stressed is that when equipment is found to be in need of repairs those repairs should be made immediately, remembering that a stitch in time saves nine.

Some operators apparently are inclined to use as an argument against the following of these rather simple rules that the time to do these things is not available without interrupting drilling. This is not a valid argument for two reasons. First, inspection and repairs can usually be made during times when drilling operations have been interrupted for some reason, such as waiting on cement or when moving locations. Second, even if it is necessary to suspend drilling operations when inspection and repairs are made, the loss entailed by failure to make hole for a few hours is more than offset by the assurance gained that the control equipment will function properly when it is called into use. Also, one should not overlook the fact that even though the better designs of control equipment are so constructed as to permit simple field repairs, a periodic shop overhaul and test should be the rule if one expects to obtain maximum useful service life and trouble free operation. The following of these maintenance practices involves such little cost that even the operator who is barely able to make his payroll should be able to afford them.

I-g. Failure to give complete and concise instructions to subordinates, and insufficient supervision. The necessity of giving complete and concise instructions to the men charged with performing a certain task is so obvious that most operators would be surprised

OTIS PRESSURE CONTROL SERVICE - EQUIPMENT

Sub-Surface Facts

ON THE CONTROL OF FLOWING WELLS

OTIS PRESSURE CONTROL SERVICE - EQUIPMENT

No. 13 1944 DALLAS, TEXAS

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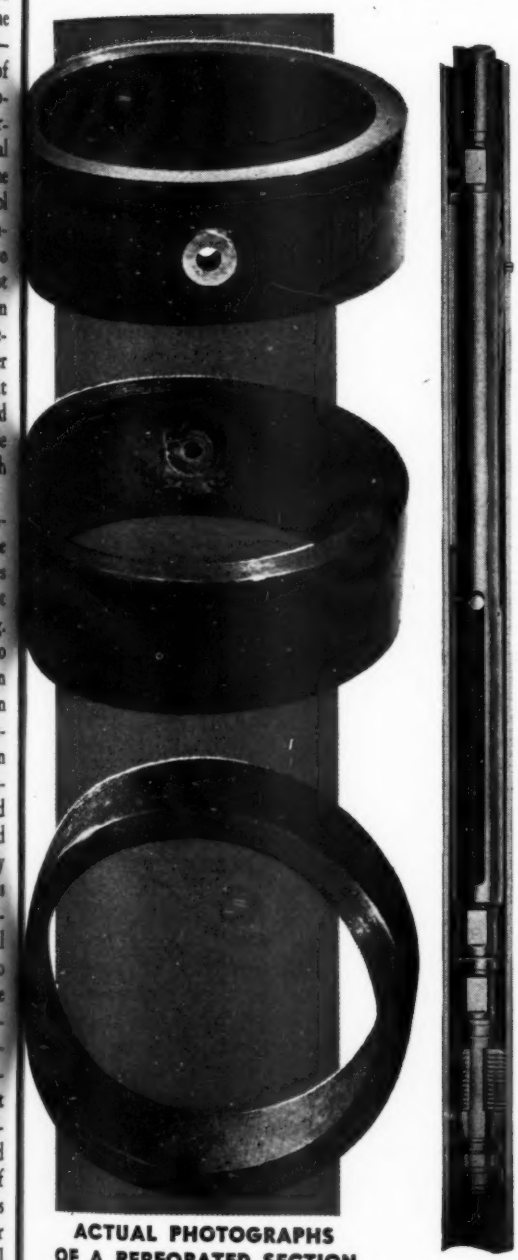

ACTUAL PHOTOGRAPHS OF A PERFORATED SECTION

1. Straight-on outside view of tubing shows tapered cylindrical insert in place. Note lack of distortion and the perfect fit of insert within the clean-cut hole.

2. Insert is driven 1/32" beyond inside diameter of tubing. This lets inside perimeter of the hole through tubing wall shrink or contract and lock insert securely in place.

3. This view illustrates the perfect round and full opening maintained in the tubing. There are no shoulders or restrictions to prevent swabbing or running of bottom hole pressure gauges, paraffin scrapers or other sub-surface tools.

ORIFICES OF ANY SIZE PLACED IN TUBING WALLS AT DESIRED DEPTHS WITHOUT MOVING TUBING OR KILLING WELL.

Equipping a well for gas lift now requires only a few hours' time. No longer is it necessary to pull the tubing to install jet collars or flow valves. Instead, the Otis Tubing Perforator is used to drive inserts containing orifices of a desired size through the tubing walls and to securely lock them in place. The complete operation is done under pressure on an ordinary steel measuring line in much the same manner as a bottom hole choke is run and set.

PERFORATOR MECHANICALLY OPERATED—NO EXPLOSIVES

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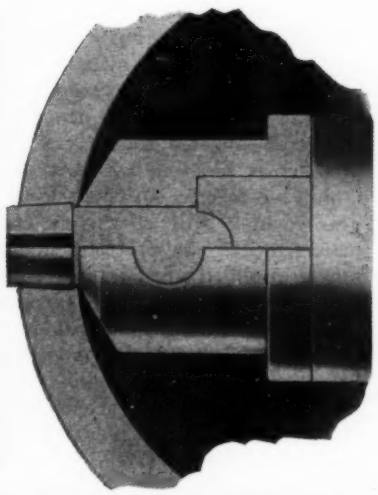
With the use of tubing jars, a small, hardened steel insert containing an orifice is driven through the tubing walls. The size of the orifices ranges from $\frac{1}{32}$" to $\frac{9}{32}$" in diameter. If a greater capacity is desired than will pass the largest insert, more than one may be used, or the insert can be eliminated altogether and an orifice of sufficient size punched directly through the tubing.

INSERT SECURELY LOCKED IN PLACE

The orifice insert is slightly tapered so that the hole punched into the tubing is expanded as the insert is driven to its ultimate position, which is $\frac{1}{32}$" beyond the inside diameter of the tubing. This permits the inside perimeter of the hole punched in the tubing to shrink back of the insert, locking it against backward movement. The taper, of course, prevents forward movement of the insert. So securely is the insert locked in place that 5000 p.s.i. pressure differential across the insert in either direction will not force it from its seat or cause it to leak.



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to learn that it is not always done. However, several blowouts that have occurred may be traced to the fact that even though the superiors were aware that certain conditions existed which would require specific action at a given depth, this information was not passed on to the man in charge of the rig. This is one of the contributory causes of blowouts under the control of management that costs absolutely nothing to correct, so the only excuse that any operator can offer who fails to observe this simple rule is, "I forgot." The other phase of this particular topic is, that even though complete instructions are given, insufficient supervision is provided to see that these instructions are carried out. One man cannot be expected to adequately supervise several rigs, particularly if they are on widely scattered locations, nor is it physically possible for one man to supervise even one rig 24 hr. a day indefinitely without relief. This is a point that certainly deserves careful consideration on the part of management, for it cannot be mere coincidence that a large percentage of the blowouts occur when no one is present at the rig but the drilling crews.

I-h. Lack of a practical educational and safety program. The value of a practical educational and safety program has been stressed by all writers on the subject of blowout prevention, and it is strange that so few operators have adopted such a program in view of the fact that practically no expense is involved. It has been stated many times that blowout occurrence can be successfully controlled only through close coordination and team work. As stated by Carpenter[6]: "Each workman should be warned of the dangers attending a blowout and be instructed in safe methods of prevention. Explanation of the design, function, and operation of different kinds of preventive equipment should be included in the instruction, with special emphasis placed on its manipulation. There is no substitute for actual practice as a means of learning to operate any mechanism, and daily drill periods for each crew of workmen are strongly recommended. A 'blowout drill,' as it is frequently called, serves to test all preventive equipment (blowout preventers, flow-line valves and pumps) and to furnish the workmen practice in its manipulation.

"Blowouts often occur when least expected, and quick action is necessary to prevent serious damage to well and equipment. To facilitate coordination, each member of the drilling crew should be assigned to a post of duty to which he should go immediately when an alarm is sounded . . . Each 'blowout drill' should be pursued with as much diligence and dispatch as any other part of the drilling operations and should be fully executed. Regular practice will promote better teamwork and tend to eliminate confusion, which sometimes exists as a result of excitement and fright." Also Vietti and Levy[3] offer the following: "The point must be emphasized that, after the installation of the most satisfactory of the various available methods of control, then the safety program is up to the operative personnel. A good, careful driller will have the least trouble, because he is essentially a safe workman. He must be allowed to play safe and he must not be pushed for footage at the expense of safety. Above all, his supervisors must be blowout conscious. Blowouts may and will be prevented if the whole organization is behind this important safety program. Such a program will return exceptional dividends to the operator."

A well planned educational and safety program is particularly essential during these war times, as the caliber of drilling crew personnel has been forced to an all-time low. It appears from replies to the questionnaire that some companies leave the matter of blowout education up to their safety department. The effectiveness of this plan is questioned for it is doubtful that there are many safety engineers who are qualified to deal except in a superficial manner with the necessary safety factors required in preventing blowouts. Specific suggestions on the education of workmen to make them blowout conscious are offered in the following part of this paper. If management can be made to realize the importance of education from the standpoint of blowout insurance so that they will institute a planned program, a backhanded, but nonetheless beneficial, result would accrue in that in planning an educational program for the workman it would be necessary that the operators make a study of the subject and, hence, would be better educated themselves.

Whereas, as stated before, it is almost impossible to offer an educational program which will effectively impress management, the problem should be much simplified when dealing with subordinate personnel such as the drilling crew. One medium that should be highly effective but which has apparently been overlooked is by means of posters similar to those one sees around machine shops dealing with such safety precautions as the use of safety goggles, etc. Of course, one sees safety posters around some drilling operations. However, these posters are usually designed to reduce injuries to personnel by calling attention to various occupational hazards. Since it is a well known fact that we learn more through our eyes than through our ears, it seems that the poster medium of education offers great possibilities in creating blowout consciousness in the workmen. If you will examine each of the causes of blowouts under the control of subordinate personnel, all of you can, probably in a very short while, visualize posters which would not only call the workmen's attention to the various hazards but would also give information on the basic reasons as to why certain things are bad practice.

The field of poster design is one entirely foreign to the author. However, in interest of illustrating the point, let us examine each of the causes of blowouts which may be corrected by the men in the field, and attempt to suggest an educational poster devoted to each cause.

II-a. Drilling gas sands too fast. The underlying reason for not drilling a gas bearing sand at too rapid a rate is that gas which is contained in the voids of the formation being drilled becomes mixed with the drilling fluid as the bit penetrates the gas bearing strata and, thus, causes the drilling mud to became gas cut and lightened to the extent that it will not overcome the formation pressure. This is a very simple concept, but one wonders how many present day drillers realize that this is what the superintendent has in mind when he instructs him not to drill a doubtful sand at faster than a given rate. It seems that this instruction, together with the reason for it, could be well covered in a graphical manner by a poster. For example, a poster might be headed "Don't Hurry When Drilling Gas Sands." Below this there might be three schematic and somewhat fanciful cross-sectional drawings of the well bore and the derrick. The first drawing would show in suitable colors the hole full of mud whose weight is holding back pressures in shallower formations, these pressures being represented by little devils, and the drilling bit just entering a sand charged with gas, the gas being shown in red. The next drawing would show the bit entered some distance into the gas sand, a pinkish tint to the lower end of the mud column, and a broad grin on the faces of the little devils. The third drawing would show the bit somewhat farther into the gas sand, a distinct red cast to the column of drilling mud, which is, by this time, blowing over the top of the derrick, and the little devils from the pressure bearing zones gleefully scampering up the hole. Of course, the drawings should be supplemented with printed explanation in bold type which the men would read after the drawings attracted their attention.

II-b. Pulling drill pipe off bottom too rapidly. Even when the bit is not balled up, and when the drill collars are not oversize, there is a pressure drop at

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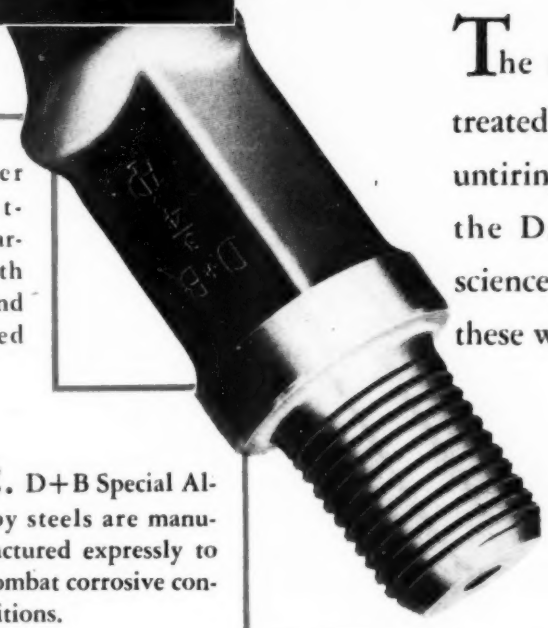

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the bottom of the drill stem when it is raised off bottom. This pressure drop is in proportion to the length of the drill pipe, the gel strength of the mud, and the rapidity of raising the pipe. Cannon[1] measured pressure drops of 375 lb. per sq. in. and it is thought by Vietti and Levy[2] that the actual pressure drop is somewhat higher than measured by Cannon. A pressure drop of 300 lb. per sq. in. is equal to the removal from the hole of 800 ft. of mud weighing 9.5 lb. per gal. Even momentary drops in pressure permit the entrance of gas into the well with the result that the mud becomes gas cut and the final effect is the same as caused by drilling a sand too fast. Here again it is doubtful that any but the best drillers have ever stopped to analyze why they have been taught not to withdraw pipe from the hole too rapidly. In trying to bring this point home to them graphically, a poster somewhat along the same lines as the one just described might do very well, but another picture might be worth considering. Visualize a poster entitled "Don't Pick Up the Pipe Too Fast or You'll Pull Hell Into the Hole," with the first drawing showing the bit on bottom and the hole full of mud holding an artist's conception of hell in check. The next drawing would show the pipe a short distance off bottom, the hole only partially filled with mud, and the inferno of gas rushing into the region of low pressure below the drill pipe, and proceeding up the hole.

II-c. Balling up the bit or drill collar by crowding in sticky formations, and **II-d. Using too large a diameter drill collar.** These two points are listed separately for the reason that they may come under the jurisdiction of more than one person. However, they may be discussed together since they are very closely related as a contributory cause of blowouts. It is probably obvious to most drillers how drilling sticky formations too fast will allow the cuttings to ball up and pack around the bit and how this condition is aggravated by oversize drill collars. It also should be apparent to them how these packed cuttings make a perfect swab as the pipe is withdrawn from the hole. The danger entailed in pulling a balled up bit is so well known to most drillers that it is doubtful that it is ever done intentionally. Therefore, it is thought that a poster devoted to this topic should be so designed as to call attention to the fact that the bit may be balled up without the driller's knowing it. Since swabbing action is so well known and easily understood, a drawing would not be necessary to illustrate the point, but would probably be desirable as an eye catcher. The poster might be headed "Don't Swab Until Tubing Is Set," and then point out the importance of being sure that the bit is not balled up before picking up the pipe and how this may easily be checked by stationing a helper to watch for an overflow of mud from the hole as the pipe is withdrawn.

II-e. Pulling pipe out of the hole before the mud is in proper condition. It should be easy for even inexperienced drillers to understand that even though the mud in the slush pit is in excellent condition, the mud in the hole may be in an entirely different physical state. Not only may the mud in the hole be full of cuttings, but also may be gas cut due to too fast drilling of a sand, or to swabbing action. Since the only satisfactory way of getting mud in the hole is through the drill pipe, it is obviously highly undesirable to have a well start kicking while pipe is out of the hole. Therefore, the only safe procedure is to lift off bottom and circulate a sufficient length of time to be sure that a complete cycle has been made and that the hole is full of clean, fresh mud before coming out of the hole. The length of time required to get returns from bottom, of course, varies with the size of the hole being drilled, the depth, and the capacity of the slush pumps. Since the time required for this operatoin is apparently often underestimated, a poster dealing with this subject should clearly indicate the minimum length of time required under given conditions, in addition to an eye-capturing drawing pointing out the danger of coming out of the hole before sufficient pumping has been done. Leaving the exact nature of the drawing to the poster designer, the chart showing the time required to get returns from bottom should, in interest of simplicity, be devoted to the particular conditions that exist on that rig. This could be easily accomplished by leaving a blank space for the chart on the poster, but sending out with the poster several charts covering different pump sizes and hole sizes. The superintendent could then paste the chart that was proper for a given job on the poster before posting it.

II-f. Failure to run fill-up pump frequently while pulling pipe from hole. All workmen, no doubt, understand that drilling fluid is displaced when drill pipe is run into the hole, and conversely, the level of the mud is lowered as drill pipe is withdrawn. However, there are many of them who do not realize how much the level is lowered even in a comparatively large hole or how this condition is multiplied as the diameter of the hole decreases. One point that many of them may overlook is that the mud inside of the drill pipe should be disregarded because it usually flows out of the opening in the bit so slowly that a large part of it is lost as each stand is disconnected. Therefore, it is thought that an excellent subject for a poster would be the data given in tabular form by Carpenter, wherein he shows that withdrawing 100 ft. of 4½-in. O. D. drill pipe from a 15-in. hole results in 10 ft. reduction in mud level; whereas, withdrawing the same pipe from a 7-in. hole causes a drop of 70 ft. A poster entitled "Don't Forget to Fill Up When Coming Out of the Hole" might illustrate a section of hole 100 ft. deep and 15-in. in diameter, with the drill pipe in place and full of 10 lb. mud exerting a pressure of 52 lb. per sq. in. on bottom. Alongside this there would be a drawing of the same hole with the drill pipe removed, the mud level lowered 10 ft., and a pressure of 47 lb. per sq. in. showing on bottom. Below this would be a pair of drawings illustrating the same condition for a 7-in. diameter hole where the mud would be lowered 70 ft. and the hydrostatic pressure reduced to 16 lb.

II-g. Use of low pressure fittings in high pressure control manifolds. Any one who has ever spent much time around a drilling rig has no doubt seen vital control lines intended for handling high pressures but containing low pressure fittings, such as cast or malleable iron, screwed end, tees and ells. Also, it is not uncommon to see high pressure flange connections hung together with maybe three or four small square head bolts. Since the old adage about a chain only being as strong as its weakest link is so well known, it is hard to understand why even careless workmen will rig up connections, which they know to be important, with fittings which will not stand the pressure. Probably, many times they realize that the fitting is not the proper one to use in that place or that the bolts are not right for that flange, but since they can't find the proper fittings or bolts at that minute, they go ahead and install the wrong one with the idea that they will change it later, but forget to do so. This is one of the things that could be overcome by an adequate inspection plan as mentioned earlier in this paper. However, in addition to this, the men should be taught that it is courting trouble to use light weight connections in high pressure manifolds. A poster devoted to this topic might be headed "Don't Send A Boy to Do A Man's Work." It might show a fanciful drawing of a manifold made up of big, robust fittings obviously having no trouble holding the pressure in control, but containing a scrawny little fitting which is obviously sweating and straining and on the verge of giving up.

II-h. Procrastination in making rig repairs. Human nature being what it is, people are inclined to put things off until tomorrow. Therefore, it is not

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too surprising to often find control equipment that needs repair, such as new packing in a blowout preventer, and even though the drilling crew is aware of this need, they just have not gotten around to doing it. It probably doesn't occur to the men, but it is nonetheless true, that control equipment in bad repair is almost as bad as no control equipment at all. Obviously, several good posters could be designed around this subject using such catch phrases as, "A stitch in time saves nine," "Do it Now." etc.

II-i. Continuing to drill or circulate during a heavy rain. Heavy rains present an ever present hazard for they will soon thin and lighten the drilling mud to the danger point. The safest procedure is to shut down the pumps and pull the pipe up into the casing or out of the hole when a really heavy rain storm occurs or threatens. However, this cannot always be done and, since even a light rain may do more harm to the mud than may be imagined, the men should be schooled in paying particular attention to the condition of the mud during bad weather so that the addition of weighting material or similar steps may be taken before it is too late. To illustrate the point, a poster entitled, "Drilling Mud Hates Rain," would show the cross-section of well bore and derrick with the sun shining and the heavy drilling mud (indicated by a dark color) holding the little gas devils in check. The next picture would show the rain coming down, the mud diluted (as indicated by a lighter color), and the little gas devils entering the well bore. Printed matter below these drawings would give specific instructions to be followed during a rain storm.

II-j. Failure to maintain the reserve mud supply in condition for use. The importance of an adequate reserve supply of drilling mud for use in an emergency was discussed in the early part of this paper. However, drilling mud in the reserve pits is of little value if it is not in condition for almost instant use. This is a fact which is often overlooked by the drilling crews and, as mud lying idle usually deteriorates rather rapidly, it is often found that the reserve mud cannot be used when it becomes necessary to call it into service. A poster which might aid in keeping this matter under the attention of the workmen might simply show a picture of a mud pit which is dried out and cracked open due to evaporation and could be entitled "Don't Forget About Your Reserve Mud Supply." Below the picture there should be a brief statement as to the importance of reserve mud with suggestions for keeping it in the proper condition for use.

II-k. Lack of general vigilance for the unmistakable signs of gas. Although one often hears statements to the contrary, it is doubtful that any well ever blows out entirely without warning. Often a blowout may be attributed to abnormal pressures for the reason that the mud had been checked immediately prior to the blowout and found to be in proper condition. However, when the trouble is later overcome, the pressures are found to be normal and, therefore, the mud in the hole must *not* have been in proper condition. If all the facts could be learned, there would probably be ample evidence before the blowout started that trouble might be expected. Experienced and careful workmen are familiar with the unmistakable signs such as the pump speeding up, the mud level in the pit rising or falling, a back flow through the drill pipe when making connections, etc., which give warning of impending trouble. However, there are probably many workmen in the field today who would probably not even notice these occurrences and, if they did, would not realize their significance. Therefore, it seems that a whole series of posters might be devoted to this topic, each poster treating with one of the advance notices that blowouts usually give, and pointing out that it pays to believe in signs.

II-l. Failure to obey specific instructions. Replies to the questionnaire indicate that several recent blowouts may be largely blamed on the fact that the men did not follow specific instructions. The reason for not having followed instructions is not clear, but regardless of whether it was due to carelessness, negligence, or to the driller thinking he was smarter than the man giving the instruction, it appears that it should be reimpressed on the men that when specific instructions are issued there is a valid reason for them, and that they should be followed if it is at all possible to do so. Of course, if a man insists on disobeying instruction, he can always be disposed of. However, this seems to be a negative attack as the damage will have already been done. Since it is well known that men are more inclined to cooperate in following instructions when they know the reason behind the instructions, it is thought that the general educational program which has been suggested above will be beneficial from this standpoint alone. However, some further good might be accomplished by a series of posters devoted to such subjects as "Pay Attention," "Don't Let Instructions Go In One Ear And Out The Other," "If You Don't Understand Instructions, Don't Be Afraid To Ask Questions," etc.

The above remarks have given considerable emphasis to an educational program through the medium of posters, as it is thought that such a program could be set in motion without much delay and is one which has been proven highly effective in other fields of endeavor. However, an educational program should not be restricted to this one medium but should include the conventional educational means of written texts and personal instruction. In regard to written texts, the Naval Air Forces have developed a scheme, which though rather unconventional seems to be highly effective, whereby the technical points are supplemented by cartoons showing what may happen as a result of an error in judgment or of not following instructions. In these cartoons, Dilbert, an imaginary student who does everything wrong, makes vivid with bitter humor, mistakes which might otherwise be learned only through costly experience. The preparing of a comprehensive educational program will no doubt entail considerable effort; however, there is little question but that the dividends will be out of all proportion to the time and labor expended.

In conclusion, it may be stated again, as it has been stated many times before, that the prevention of blowouts lies in the hands of the operators and their personnel. The combination of blowout conscious management, good equipment, proper drilling mud, and well-educated and well-trained drilling crews is the best blowout prevention insurance available.

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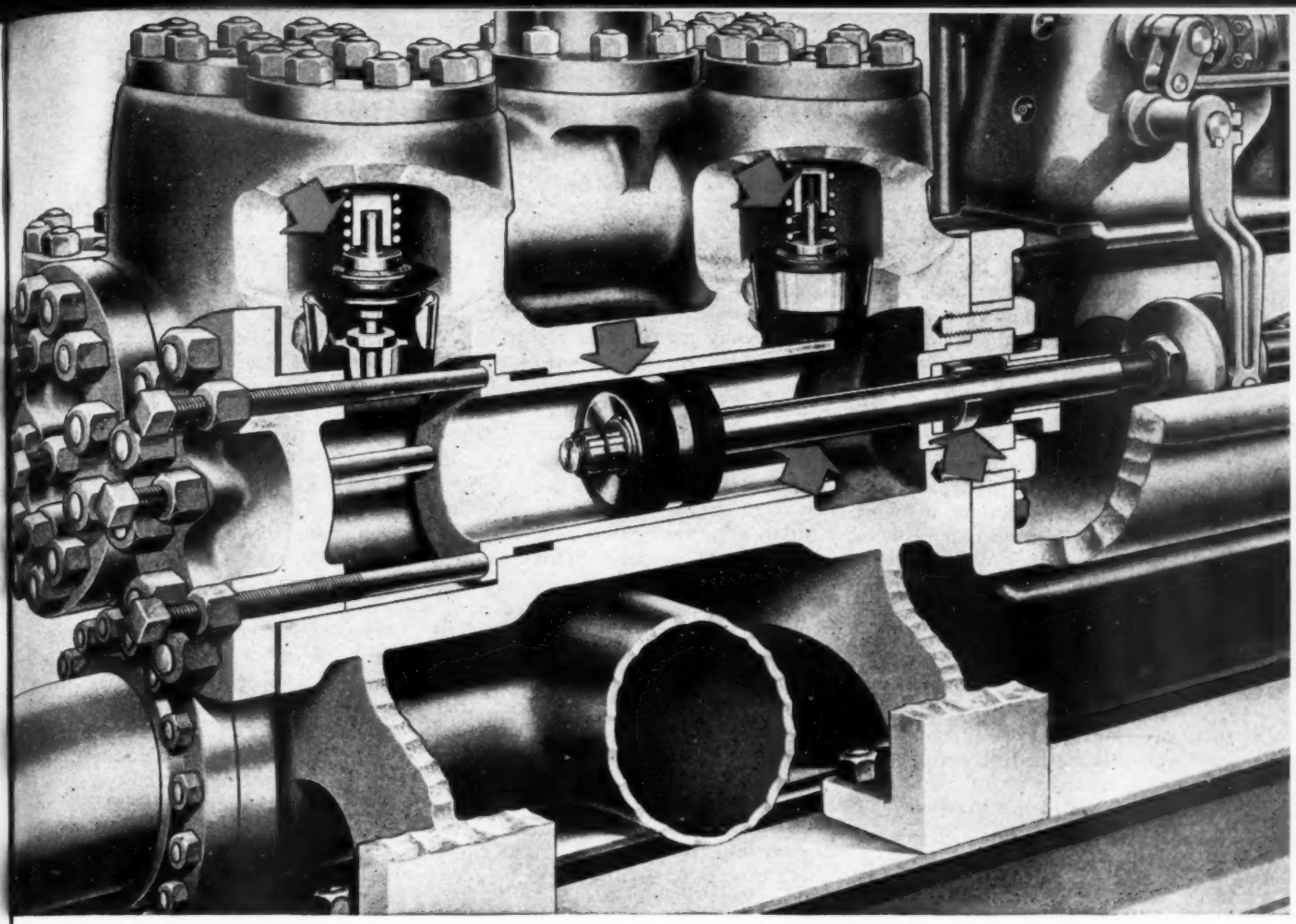

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Coring With a Reverse Circulation Rig*

By LEWIS FINCH, JR., and WHITNEY M. ELIAS
Stanolind Oil and Gas Company

CORING of geological sections has long been accepted by the oil industry as a means of determining physical characteristics of underground reservoirs. In some geological sections representative samples, for example from sand and shale sections, taken in conjunction with other methods of formation logging, are sufficient for evaluating controlling characteristics. However, in other sections, particularly the dolomitic limestone sections in West Texas, where it is extremely difficult to determine accurate formation characteristics by methods other than coring, it is almost essential that continuous cores of the producton section be cut and recovered. Incomplete core recovery is often of no value. Therefore, even if it were considerably more expensive than procedures normally employed, any applicable method of coring that will result in recovery of the entire section cut is worth investigation.

The necessity of pulling drill pipe to recover cores has been partially overcome by the use of the wire line core barrel, but the amount of core being recovered in this manner is not known until after pulling the barrel.

The reverse circulation coring process has been used with core drill equipment. The possibility of adapting a similar principle in conventional rotary coring appeared feasible. Three factors led to conducting the experiment on a reverse circulation rig in preference to a large rotary rig.

1. In many operations in West Texas reverse circulation rigs, using oil as a circulating medium, drilled the pay section after the oil string had been set. The equipment was simple and relatively light and could be economically adapted to reverse circulation coring.

2. The size of the formation cuttings recovered with normal reverse circulation rigs indicated that normal circulation volumes and pressures in the fluid stream were sufficient to raise a core fragment to the surface.

3. The proved feature of providing a quick reversal of fluid input from the annulus to the drill pipe also appeared attractive as a means of dislodging "bridged" core fragments from the drill pipe without a pulling job.

In adapting the reverse circulation rig for this process several factors had to be considered; first, the experimental nature of the project would not warrant purchase of the patented drill pipe; second, it was very questionable whether purchase of the special drill pipe would be permitted under war emergency orders; third, the curvature of the conventional gooseneck was too sharp to permit free passage of core fragments and fourth, internal diameters of various conduits through which the core would travel from the core head to the discharge box varied to such a large degree that serious complications were anticipated as a result of variation in fluid velocity from point to point.

With these primary factors in mind, the problem was attacked by both the rig owner and oil operator. Several fundamental changes were made in the equipment preceding the first trial runs. It was found that the hexagonal kelly and rotary drive bushing, an integral and essential part of the rig, were the main restrictive elements. The inside diameter of the kelly was the maximum limit to the size core that could be cut and retrieved. With 5½-in. oil string, a 4¾-in. cutter head was the largest size that could be used. The formation to be cut was a hard anhydritic dolomite that required the use of a hard formation cutter head. Two types of cutter heads were available; one with a 2½-in. and the other with a 1 11/16-in. core course. As 2-in. E. U. E. tubing with an I. D. of 1 15-16 in. was being used for drill pipe the latter was satisfactory. The standard gooseneck was replaced with a piece of 2½-in. tubing bent with a 4-ft. 6-in. radius of curvature and a 2½-in. by 3-in. swage was fixed to the downstream extremity. This swage contained a 2-in. nipple that extended through the rotary hose coupling to prevent obstruction occasioned by cores lodged in the coupling. The internal diameters limiting core travel were fixed as follows: 1 11/16 in. through the cutter head; 2½ in. through the 4-ft. 6-in. drill collar; 1 15/16 in. through the 2-in. E. U. E. tubing; 2½ in. through the kelly; 2 7/16 in. I. D. through the gooseneck, and the 3-in. rotary hose to the sump box.

The rotary table r.p.m. was from 45 to 52, the weight carried on the core head was from 8,600 to 12,000 lb. and the pump pressure was from 350 to 400 lb. per sq. in. Later modifications were made as the needs arose and included elimination of the drill collar and replacement of the rotary hose with 2½-in. by 30-in. segments of tubing added or withdrawn from the gooseneck, dependent upon the height of the kelly above the drive bushing.

Most of the trouble initially experienced was due to core fragments lodging in the top part of the cutter head immediately below the drill collar, or in the tubing couplings. A 1¾-in. I. D. mandrel was inserted in the cutter head section and extended from slightly above the core catcher in the core head into the drill collar sub a distance of 12 in. (This mandrel was later removed and replaced with a sleeve which, in effect, plugged the fluid courses and required all fluid and cuttings to pass through the core course with the core. It was reasoned that this would assist in breaking off the cores in a much simpler manner.) Immediately below this mandrel there was inserted a hard formation core catcher, with 3 of the 6 fingers removed to assist, among other things, in breaking off the cores without raising the core head off bottom. Lodging of cores in tubing couplings was overcome by inserting 2-in. by ¾-in. ferrules in all the tubing collars.

The modifications thus far had eliminated a large portion of the subsurface difficulties. After changing the gooseneck to 2-in. E. U. E. tubing and replacing the old rotary hose with a new one and supporting the lower part of the hose with a 25-ft. trough made of half of a 12-in. pipe, 95 per cent of our trouble had been eliminated. The remaining 5 per cent was occasioned by lodging of core fragments in the tubing. A mandrel with two Skinner swab rubbers was made and when the fragments became lodged the circulation was reversed and the mandrel pumped down to dislodge the fragment.

While many of the initial problems had been overcome by these improvements flexibility had not been obtained. It was realized that almost 100 per cent of the core cut was being recovered but the adaptation of this method to conventional rotary rigs was questionable without further modification. The sharp core fragments were cutting the inside of the rotary hose and certain obstructions still existed in the gooseneck. To increase equipment flexibility, eliminate core obstruction and rotary hose wear, a conventional core barrel was inserted in the drill string immediately below the kelly. In this manner the core was circulated to the surface, caught in the core barrel and later removed without pulling the pipe. This revision eliminated the previous requirement for one member of the drilling crew at the sump box to handle the

*Presented before American Petroleum Institute Mid-Continent District Division of Production, Tulsa, Oklahoma, May 25-26, 1944.

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cores recovered. When the core barrel was first used in this manner, it was found that when about 5 ft. of core occupied the core barrel the circulating pressures increased to 800 lb. per sq. in. or more, probably due to restrictions in fluid courses by the inner barrel and piston action of the core in the barrel. The inner barrel was removed and the core catcher attached to the outer barrel. This experimentation has been very recent and it is therefore impossible to determine what further modifications will be required; nevertheless, it is evident that slight alterations can be made to overcome objectionable features. Present costs for these modifications on the standard reverse circulation rig are approximately $250.

The preceding discussion of the mechanical problems encountered and their eventual solution was given to indicate the relative ease with which these revisions could be made.

The obvious object of this experiment was to increase core recoveries. The results obtained in six West Texas dolomite wells show that out of 724 ft. cored, 702 ft. of core were recovered with a recovery efficiency of 97 per cent. The average coring time was 58 minutes per foot. Each core head used out approximately 25 ft. of section and the average total cost of a job was $2,336.98. This resulted in a cost of $19.37 per ft. of core cut, or $19.97 per ft. of core recovered. In all 6 wells the circulating fluid was oil.

In the 6 hard dolomite sections cored the fragmentation of cores was not noticeable. During the early stages of the experiment when core fragments lodged in the cutter head and tubing couplings the cores were relatively short and averaged about 2 in. in length. As improvements in the method were made and the core suffered less jarring the sections recovered averaged about 4 in. in length which is sufficient for most laboratory analyses. It was noticed that in some instances pieces of formation lying adjacent to the drilled hole were dislodged and circulated to the surface. This was realized when sections recovered totaled more than the sections cut and care had to be exercised to eliminate these fragments from core recovery considerations.

As a matter of comparison, representative data have been reviewed for other types of drilling-in methods: (1) Reverse circulation drilling using a bit instead of a core cutter head and using oil as a circulating medium; (2) conventional rotary coring using a common core barrel. Drilling and coring statistics on all three methods are directly comparable because the wells analyzed were drilled in the same or similar field and geologic section. Straight reverse circulation drilling cut the formation at a rate of 17 minutes per ft. while conventional rotary coring and the reverse circulation coring took about 3½ times longer to penetrate a similar interval. In comparing the cost per foot penetrated straight reverse circulation drilling costs $3.20 per ft. while the other two methods cost about $19.00 for a similar interval. This would indicate that the cost of coring similar sections would be almost 6 times as expensive as straight drilling.

Of most importance is a comparison of conventional rotary coring with reverse circulation coring.

Conventional rotary coring requires pulling the drill pipe to recover the core. As a general rule the per cent of core recovered leaves much to be desired. It is estimated that this method results in approximately 55 per cent recovery in the area analyzed and consequently the cost per ft. recovered relative to the cost per ft. cored increases significantly from $19.00 to about $33.00. Coring with reverse circulation has resulted in recoveries closely approximating 100 per cent and consequently the cost per ft. penetrated and the cost per ft. recovered are nearly equal, averaging $19.00 to $20.00 per ft. Actual comparison between these two methods shows that, in the area analyzed, conventional rotary coring costs 1.66 times more per ft. of core recovered than reverse circulation coring.

Based upon these facts and figures the results of the experiment appear favorable. Core recovery was definitely increased, the cost per ft. of core recovered was decreased and a reverse circulation rig was modified, at a minimum expense, to accomplish these objectives.

Experimentation along these lines is being continued and at present it appears feasible to adopt certain features of this development to coring in general. It is very possible that internal streamlined drill pipe can be used on a conventional rotary rig adapted to reverse circulation, the core head placed on the drill collar and the core barrel run immediately beneath the kelly to effect a more exact coring program. Many times it is desired to core for the purpose of locating the top of a pay zone or other geological marker whereby penetration would be reduced to a minimum. With the present procedure it is necessary to predetermine the footage to be cut and when the core is cut it must be pulled to ascertain the facts. The reverse circulation continuous coring method, where feasible, will permit examination of the core as it is cut foot by foot, if necessary, without completely pulling the drill pipe. If these modifications are extended to conventional rotary equipment there will be a real incentive to build more durable core heads. At the present time a core head need last only long enough to cut a core equal to the length of a core barrel.

Comparisons presented in this paper are based purely on experience gained in hard dolomite sections in West Texas. A few limited experiments have been made to determine, in a preliminary way, whether or not a comparable method of coring by reverse circulation might be feasible in unconsolidated sand and shale sections in the Gulf Coast. These experiments indicate that large amounts of shale in the section being drilled tend to plug the fluid course in the bit. On the other hand, unconsolidated sand cores are extremely friable and, due to the vibrations caused by core fragment movement to the surface, might be expected to break up or disintegrate completely. It may or may not be possible to eliminate this type of difficulty in unconsolidated sand and shale sections.

In conclusion, results of experiments indicate that continuous coring with reverse circulation using either oil or mud may prove both feasible and beneficial in certain consolidated sand and limestone sections. The application of the same process in more friable sections will be considerably more complicated.

——— ☆ ☆ ☆ ———

Secondary Recovery in War Program

*"In our search for new oil reserves, too little attention is being given to one of our most valuable tools for discovering additional crude oil reserves. By changing our thinking from terms of new oil reserves to terms of old reserves, we have a very valuable tool in secondary recovery. The two methods of secondary recovery now being practiced on a commercial basis are water flooding and gas or air injection. These techniques of oil production are bringing about a reappraisal of the oil reserves of the nation. * * * * In many instances, the oil recovered through secondary recovery, from individual properties has considerably exceeded the primary recovery. Also, where it has taken 25 to 50 years to produce a given quantity of oil by primary operations, with operating and other expenses continuing over an equal length of time, water flooding of the property has recovered the same volume of oil in from three to five years."*

—Charles B. McClintock, PAW, before A.P.I., Tulsa, Oklahoma, May 27, 1944.

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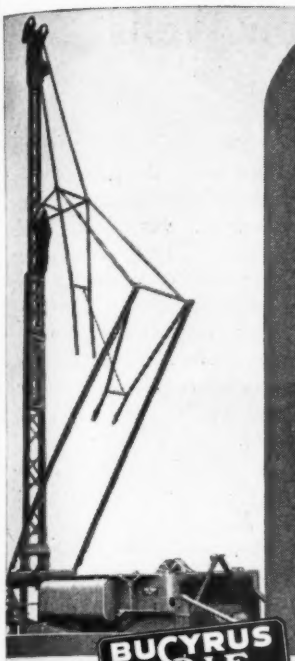
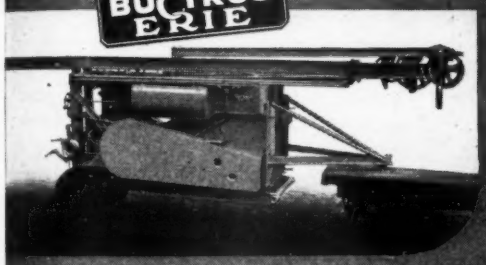
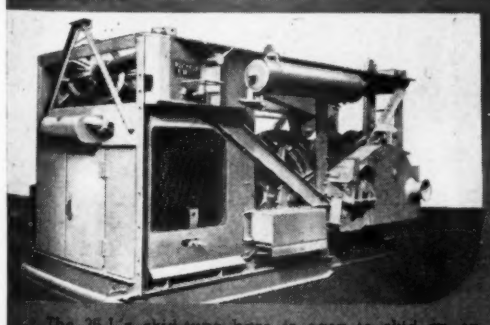


The entire derrick set up on the 36-L can be handled by two men in 20 minutes. The derrick on this machine is a strong latticed box structure of the telescoping type, extended and raised by a worm-gear-driven power winch.



A speedy mounting, available on the 36-L, is the semi-trailer outfit, with which the rig can easily be moved at 25 to 30 miles per hour.

The 24-L Spudder — mounted on a motor truck — is built for covering a large territory at maximum speed.



The 36-L's skid-type base is easy to skid on or off trucks, derrick floors, or mudboats.

With Bucyrus-Erie Spudders, mobility means more than mere "movableness;" it means really fast tear downs, speedy moves, and quick set-ups on new locations — for all three can be done in an eight-hour shift with as few as two or three men.

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Drilling Fluid for the Completion of Shallow Wells*

By W. H. FARRAND and W. A. CLARK
The Texas Company

IN the last few years, many hundreds of wells have been drilled in California by the rotary method into zones having formation pressures as low as 50 lb. per sq. in., and having permeabilities as high as 15 darcys. It may be stated that most of these were completed as producers, despite the method of drilling and the lack of pressure in the zones. Nevertheless, it may be debated as to whether higher initials could be obtained by using better completion methods and a proper fluid for drilling into the producing zone.

The majority of the wells were drilled and completed with water-base drilling fluid made from California native muds. Recently, however, considerable attention has been paid to improving the character of drilling fluids to lessen possible harmful effects on initial and settled production.

Special fluids, either to drill in with or for final completion of the well, have been used in an attempt to improve productivity. These fluids have consisted of oil-base fluids, bentonitic gel fluids, and chemically treated water-base muds.

Attention was directed to the possible harmful effect on low pressure sands of too heavily weighted muds, which might force mud fluid into the sands. Consequently, the use of low weight, 70-75-lb. fluid, is now considered the proper procedure.

With the use of water-base muds, the effect on permeability of the water filtrate seeping into the sands or the formation of a "water block" were taken into account. Rapid completion following penetration of the sand may minimize these conditions.

Thought was given by some that by the time a liner is run and the well completed, the effect on production of an excessively thick and perhaps impervious mud cake occurring on the face of the sand which could not be dislodged by the low pressure formational fluid, would be excessively harmful. This might be particularly true if very fine mesh perforations or gravel pack were used unless the annulus was thoroughly flushed.

On a well completed last year two runs of the hole caliper were made, the second run being 5 hr. after the completion of the first run. This well was drilled with a good water-base mud in a highly permeable sand. Your attention is called to the thickness of the well cake deposited opposite the sands of the producing zone in this 5-hr. interval. This, of course, only shows the mud cake deposited. It is no measure of the filtrate water which must have penetrated the zone during this period of deposition of wall cake. (See Fig. 1.)

Water-base fluids — effect of water on oil zones. From laboratory data and some field experience, it is common knowledge that water, particularly fresh water, seeping into certain sands in some way impairs permeability, which may result in a decrease in oil productivity.

A well in the Signal Hill field completed in the middle of 1930 for 80 bbl. per day average for the first month gradually built up in production until in 1934 it averaged 130 bbl. per day for a 3-month period. There was no change in the producing method employed on this well yet gradually the production built up and water block in a tight sand is suspected as the cause, or reason for the low initial production.

A well at Paloma was completed in sands of low permeability with water-base mud at rather a disappointingly low rate of 34 bbl. per day, 47.8 gravity, 360,000 cu. ft. During the succeeding weeks, production from the well rose gradually to a figure of 85 bbl. per day, 54.5 gravity, 840,000 cu. ft., indicating an initial water block although another factor, gun-perforating, may have influenced the well's behavior.

One investigator has made laboratory tests on the permeability of sands to various fluids. The results of the experiment indicate that the permeability of a sand may be reduced as much as 60 times when penetrated by fresh water. When the fluid was changed to salt water on a core of a similar type sand the permeability was reduced only 20 times. Two other experimenters, working independently of each other, arrived at the same conclusion, namely, that any water loss into the producing sand is harmful.

The importance of this observation is that although a little water loss is probably less damaging than a lot of water loss, it is possible that the effects of the little may be greater than heretofore suspected.

Impaired permeability may particularly occur in sands of Continental deposition, which contain ashy material or a large percentage of feldspar, together with their decomposition products, bentonite and kaolin, respectively. Some specific field experience can be cited. One well in the Mt. View field after being completed for 1160 bbl. per day of 21.3 gravity oil in the Chanac zone was killed and deepened. Later, when the well was plugged back to this zone, only 106 bbl. per day could be obtained on the recompletion in a heading flow. Another well in the same field flowing 784 bbl. per day net oil was killed with mud and water for the purpose of plugging. Upon recompletion, the best rate obtainable was 264 bbl. per day.

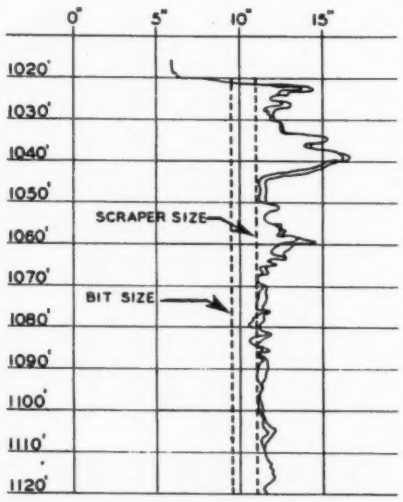
Experiments on sands in Cole's Levee, which contain a high percentage of feldspar, have shown a great decrease in permeability when fresh water has been pumped through them for a number of hours.

Experiments in the North Cole's Levee field and the Wilmington field have indicated a few examples that production rates are lower upon recompletion after wells have been killed with water.

The Temblor sands at Kettleman Hills often lose their productivity when exposed to formational waters, necessitating redrilling operations to bring the wells back on oil production.

A Dominguez field well was completed as a 4000-bbl. producer. Owing to a leak in the tubinghead, it was necessary for the operator to kill the well to change this connection. The well was killed with water. When recompleted, the productivity index was much less than on the original completion, and although the well improved over a long period of time, it never regained its original productivity.

Fig. 1. Second run 5 hr. after first. Note wall cake increased thickness



*Presented before American Petroleum Institute Pacific Coast District Division of Production, Los Angeles, March 23, 1944.

A-C Production Equipment

In the recompletion of some damaged wells an operator found that the recompletions were as good or better than the original completions. The operator attributes this to the short time interval the sands in these wells were exposed to the drilling fluid while recompleting.

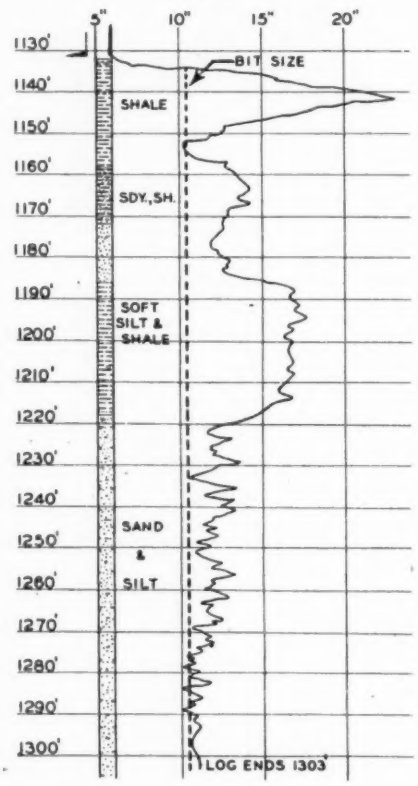
At Signal Hill a DeSoto zone well was completed with a conventional liner and the well was swabbed for 30 days. During this period, over 600 bbl. of fluid, mainly salt water, was recovered from the interval opened. This recovered water was tested by the laboratory and traces of phosphate used in the drilling mud were detectible at the close of the 30-day period. While this is not a large volume of water, the presence of the phosphates definitely indicate that the water from the drilling fluid had invaded what should have been the producing zone.

Effect of water on shales. Numerous runs of the hole caliper have shown that use of water-base mud causes beds of shale and clayey silts to run, in some cases, and to gradually slough off in other cases, to such an extent that the actual hole size opposite those formations may be twice the diameter of the bit size.

Fig. 2 shows a caliper log run immediately after cleaning out the hole following the setting of the casing.

We have considerable reason to believe that the shales already soaked with

Fig. 2. Effect of water-base fluid on shales



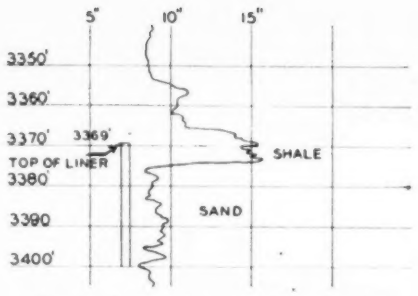


Fig. 3. Liner sheared off opposite cavity in shale

drilling water continue to run some time after the liner is in place and the well is on production. Moreover, if there is considerable annulus between liner and the sand bodies, the shale will tend to pack between the sand and the liner and wholly or partially shut off production or collapse liner. This may account for the rapid decline in production often seen in low pressure zones.

A well was completed in the Redondo field in July, 1936, with Grade D pipe. Within a few days after the completion of the well, on which the initial production was 161 bbl. per day, the liner collapsed and production dropped rapidly to a 50 bbl. per day rate. In the fall of 1943 it was decided to pull this liner and rework the well. Fig. 3 shows a caliper log of this well. The top of the collapsed liner was recovered from a depth of 3369 ft. The reason for the collapse is more or less obvious from the hole caliper run. The 15-in. diam. hole at this point indicates that the unsupported wall of the hole collapsed against the liner and sheared it at 3369 ft.

Crude oil and oil-base drilling fluids. In view of the detrimental effect of water on some formations, as indicated in the laboratory at least, a few operators have resorted to various types of oil-base drilling fluids or plain crude oil for drilling in the zone. In addition, in case of oil-base fluids, there is some thought that a cake is formed which is thinner and less tough than a water-base cake, and is easily miscible in the formational fluid.

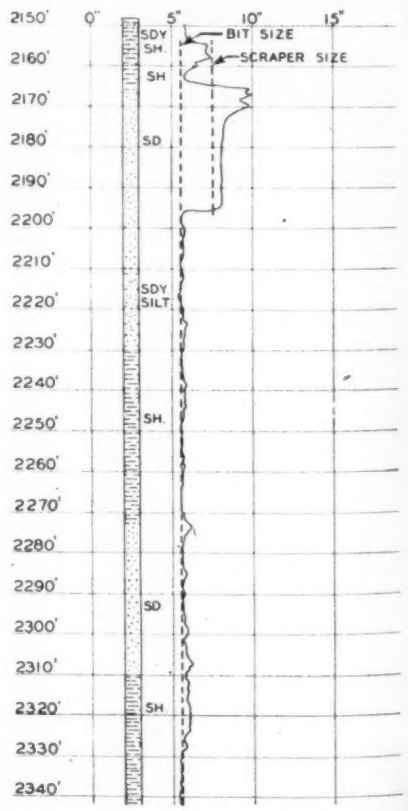
Caliper runs show that very little formation, especially shales, slough off into the hole when using one type of oil-base fluid. Fig. 4 shows a caliper log on a well drilled in and partially wall-scraped using this same type of oil-base drilling fluid. Note that the shales have sloughed but little although the loose part of the sand washed out during the scraping operation.

Moreover, experience on one well, at least, shows that there is no measurable build-up of cake with oil-base mud when standing in a well for the period of time necessary to run a liner and commencement of bailing operations. This is shown by examination of Fig. 5. On this drawing, run No. 2 was made after the well had stood for 13 hours.

Instead of oil-base drilling fluid, many operators have completed wells or attempted to, by either drilling in with crude oil or by drilling in with water-base fluid and wallscraping or washing with crude oil.

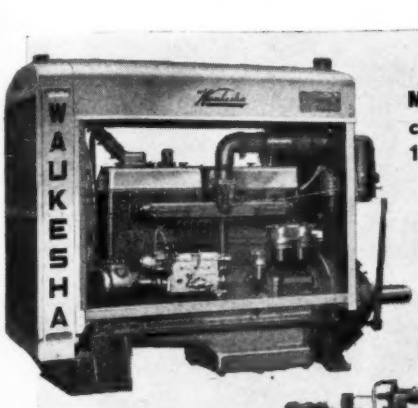
This has been successful in a number or areas. In others, however, some types of shale begin sloughing very badly when the oil comes in contact with them and in some instances hole conditions becoming so bad that it was impossible to run the liner without changing the drilling fluid. In some areas that contain shale affected by oil, it is probable that the shale continues to slough into the hole behind the liner after the well is on production, and may have the same effect as noted above, namely, that the well rapidly enters the stripper class. This condition would be aggravated by producing sand from the well which would tend to form a cavity in any sand body under shale. The shale would then slough from above the sand body into the cavity and partially or completely shut off production. The caliper log shown on Fig. 6 indicates that such a condition may exist. The well shown in this drawing was completed in a sand-shale section several years ago in the Kern Front field. Dur-

Fig. 4. Effect of oil-base fluid on hole size

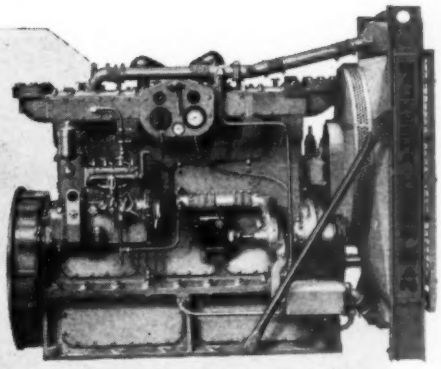


Opening New Production Fields

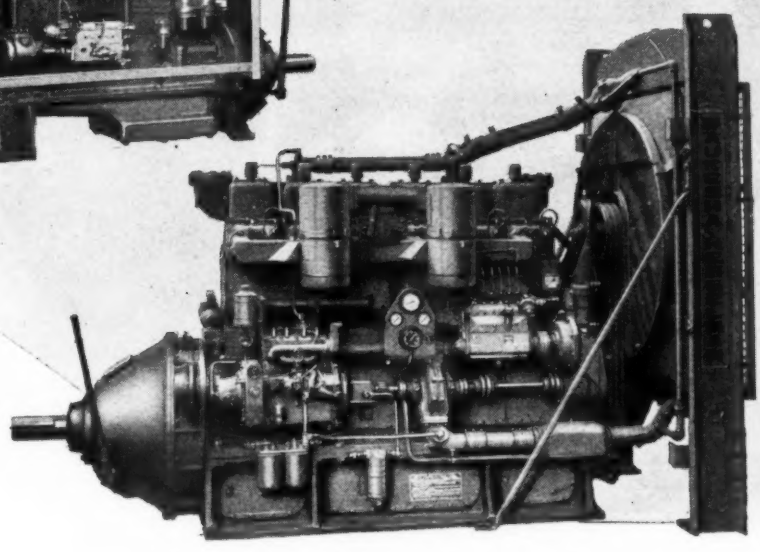
FROM TEXAS TO THE ATLANTIC SEABOARD



MODEL 6-WAKHU—diesel fuel—six cylinders, 6¼ in. bore x 6½ in. stroke, 1197 cu. in. displ., 169 hp. @ 1300 rpm.



MODEL 6-NKHU—diesel fuel—six cylinders, 7 in. bore x 8½ in. stroke, 1962 cu. in. displ., 208 hp. @ 1050 rpm.



MODEL 6-LRHU — diesel fuel — six cylinders, 8½ in. bore x 8½ in. stroke, 2894 cu. in. displ., 308 hp. @ 1050 rpm.

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1. Application of a gas carburetor
2. Application of spark plugs
3. Replacement of injectors with blind plugs
4. Unbolting of the fuel pump coupling

—an hour's work—that's all it takes to convert. No changing of cylinder heads, pistons or *any* internal parts. And, to go back to diesel-oil operation, you simply reverse the process. Even gasoline can be used as a fuel with the same simple conversion.

AVAILABLE WITH STARTING ENGINES—All three of the Waukesha-Hesselman drilling engines shown are available with independent four-cylinder gasoline engine starters. No hand cranking is ever necessary.

FOR EVERY OIL FIELD NEED — THERE'S A WAUKESHA ENGINE or Power Unit—310 horsepower to 30 horsepower diesel-oil fuels . . . 410 horsepower to 10 horsepower gasoline or gas.

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MORE POWER FOR VICTORY

WAUKESHA MOTOR COMPANY, WAUKESHA, WIS. • NEW YORK, TULSA, LOS ANGELES

In the recompletion of some damaged wells an operator found that the recompletions were as good or better than the original completions. The operator attributes this to the short time interval the sands in these wells were exposed to the drilling fluid while recompleting.

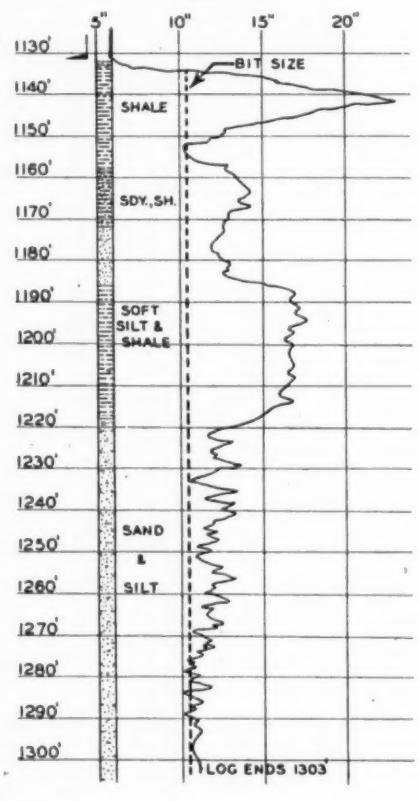
At Signal Hill a DeSoto zone well was completed with a conventional liner and the well was swabbed for 30 days. During this period, over 600 bbl. of fluid, mainly salt water, was recovered from the interval opened. This recovered water was tested by the laboratory and traces of phosphate used in the drilling mud were detectible at the close of the 30-day period. While this is not a large volume of water, the presence of the phosphates definitely indicate that the water from the drilling fluid had invaded what should have been the producing zone.

Effect of water on shales. Numerous runs of the hole caliper have shown that use of water-base mud causes beds of shale and clayey silts to run, in some cases, and to gradually slough off in other cases, to such an extent that the actual hole size opposite those formations may be twice the diameter of the bit size.

Fig. 2 shows a caliper log run immediately after cleaning out the hole following the setting of the casing.

We have considerable reason to believe that the shales already soaked with

Fig. 2. Effect of water-base fluid on shales



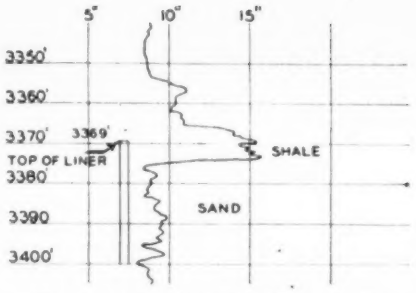


Fig. 3. Liner sheared off opposite cavity in shale

drilling water continue to run some time after the liner is in place and the well is on production. Moreover, if there is considerable annulus between liner and the sand bodies, the shale will tend to pack between the sand and the liner and wholly or partially shut off production or collapse liner. This may account for the rapid decline in production often seen in low pressure zones.

A well was completed in the Redondo field in July, 1936, with Grade D pipe. Within a few days after the completion of the well, on which the initial production was 161 bbl. per day, the liner collapsed and production dropped rapidly to a 50 bbl. per day rate. In the fall of 1943 it was decided to pull this liner and rework the well. Fig. 3 shows a caliper log of this well. The top of the collapsed liner was recovered from a depth of 3369 ft. The reason for the collapse is more or less obvious from the hole caliper run. The 15-in. diam. hole at this point indicates that the unsupported wall of the hole collapsed against the liner and sheared it at 3369 ft.

Crude oil and oil-base drilling fluids. In view of the detrimental effect of water on some formations, as indicated in the laboratory at least, a few operators have resorted to various types of oil-base drilling fluids or plain crude oil for drilling in the zone. In addition, in case of oil-base fluids, there is some thought that a cake is formed which is thinner and less tough than a water-base cake, and is easily miscible in the formational fluid.

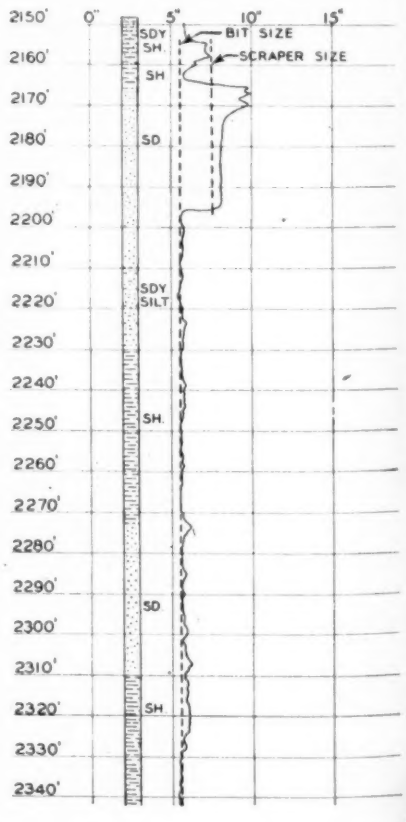
Caliper runs show that very little formation, especially shales, slough off into the hole when using one type of oil-base fluid. Fig. 4 shows a caliper log on a well drilled in and partially wall-scraped using this same type of oil-base drilling fluid. Note that the shales have sloughed but little although the loose part of the sand washed out during the scraping operation.

Moreover, experience on one well, at least, shows that there is no measurable build-up of cake with oil-base mud when standing in a well for the period of time necessary to run a liner and commencement of bailing operations. This is shown by examination of Fig. 5. On this drawing, run No. 2 was made after the well had stood for 13 hours.

Instead of oil-base drilling fluid, many operators have completed wells or attempted to, by either drilling in with crude oil or by drilling in with water-base fluid and wallscraping or washing with crude oil.

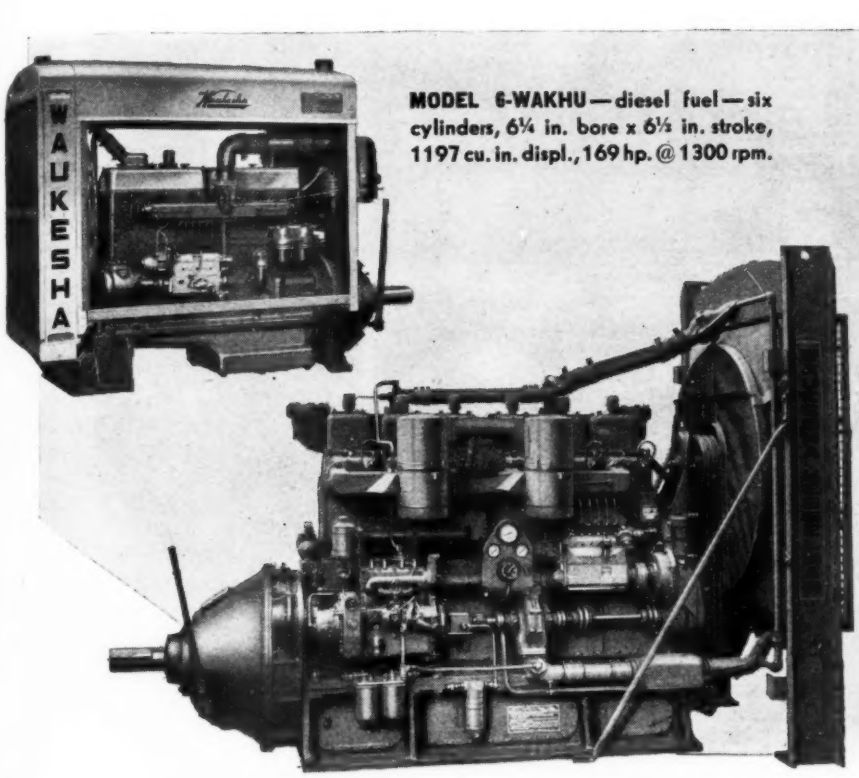
This has been successful in a number or areas. In others, however, some types of shale begin sloughing very badly when the oil comes in contact with them and in some instances hole conditions becoming so bad that it was impossible to run the liner without changing the drilling fluid. In some areas that contain shale affected by oil, it is probable that the shale continues to slough into the hole behind the liner after the well is on production, and may have the same effect as noted above, namely, that the well rapidly enters the stripper class. This condition would be aggravated by producing sand from the well which would tend to form a cavity in any sand body under shale. The shale would then slough from above the sand body into the cavity and partially or completely shut off production. The caliper log shown on Fig. 6 indicates that such a condition may exist. The well shown in this drawing was completed in a sand-shale section several years ago in the Kern Front field. Dur-

Fig. 4. Effect of oil-base fluid on hole size

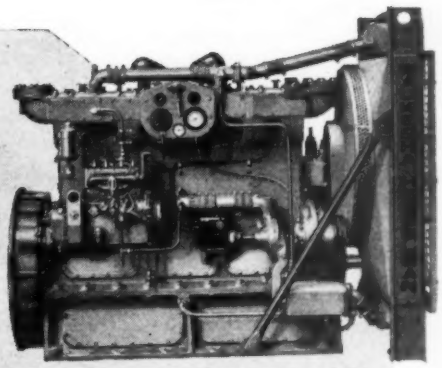


Opening New Production Fields

FROM TEXAS TO THE ATLANTIC SEABOARD



MODEL 6-WAKHU—diesel fuel—six cylinders, 6¼ in. bore x 6½ in. stroke, 1197 cu. in. displ., 169 hp. @ 1300 rpm.



MODEL 6-NKHU—diesel fuel—six cylinders, 7 in. bore x 8½ in. stroke, 1962 cu. in. displ., 208 hp. @ 1050 rpm.

MODEL 6-LRHU — diesel fuel — six cylinders, 8½ in. bore x 8½ in. stroke, 2894 cu. in. displ., 308 hp. @ 1050 rpm.

WAUKESHA

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THE WIDER ADAPTABILITY of Waukesha-Hesselman Oil Engines in drilling operations is one big reason why the demand for increased production is being met by widespread exploration and extension of field drilling.

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FROM DIESEL OIL TO GAS . . . IN 4 SIMPLE OPERATIONS . . .

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2. Application of spark plugs
3. Replacement of injectors with blind plugs
4. Unbolting of the fuel pump coupling

—an hour's work—that's all it takes to convert. No changing of cylinder heads, pistons or *any* internal parts. And, to go back to diesel-oil operation, you simply reverse the process. Even gasoline can be used as a fuel with the same simple conversion.

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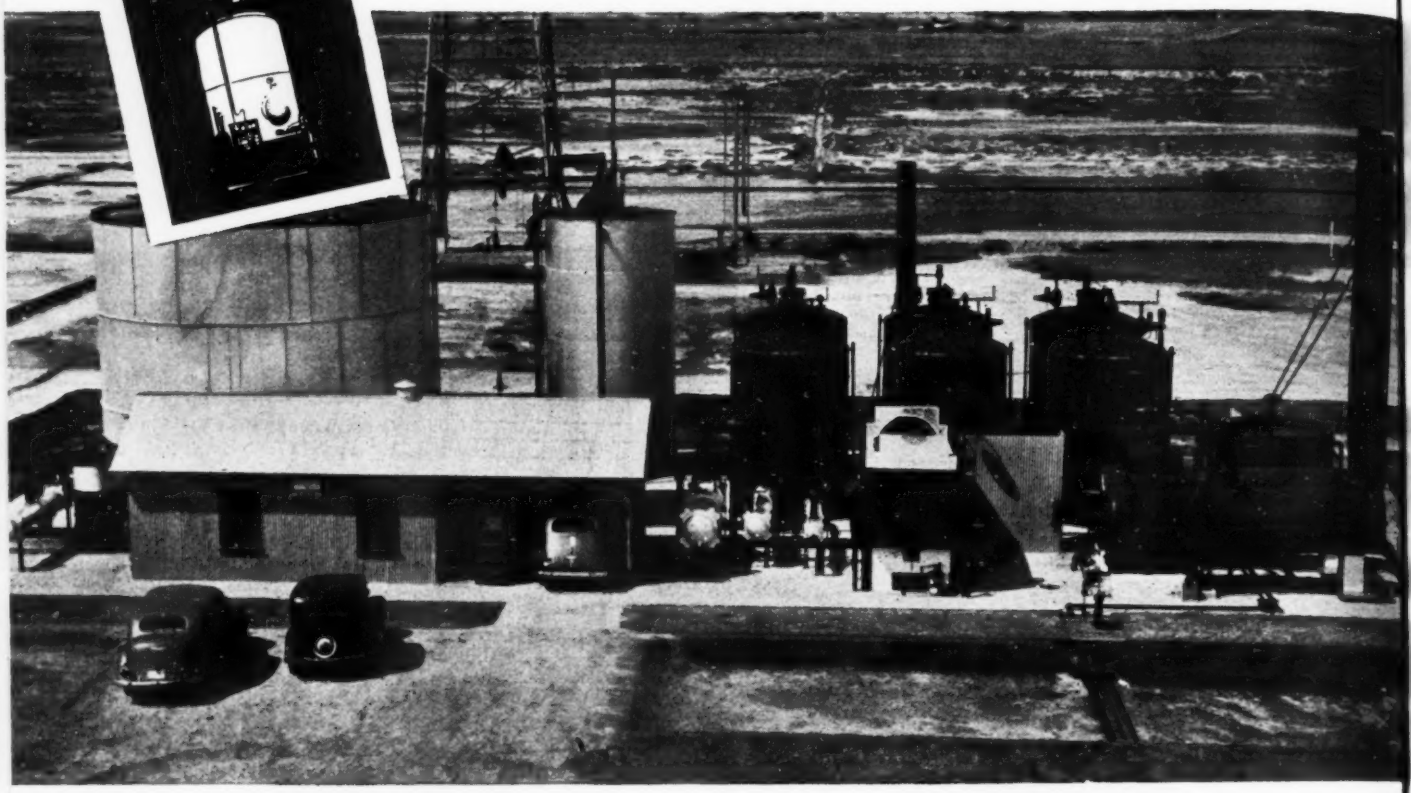
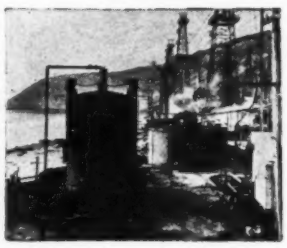
Petreco Dehydration CONDITIONS

OIL SO THAT ALL DEPARTMENTS BENEFIT



PRODUCTION

Petreco Electric Dehydration operating automatically, in vapor tight, A.P.I.—A.S.M.E. specification vessels, attains the lowest cuts, prevents extensive evaporation losses, retains true gravities and requires the minimum attention at all times.

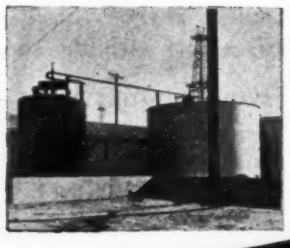


PIPELINE

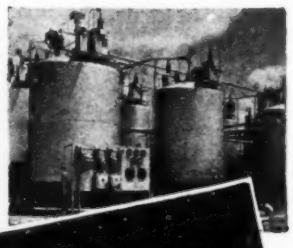
Petreco processed crude contains the minimum of B. S. and W.—thereby preventing the accumulation of tank bottoms. Pumping operations are facilitated and pump pressures reduced.

TRANSPORTATION

When crude oil is conditioned by the Petreco Process, the low residual moisture content insures maximum use of shipping facilities. With Petreco treated crude, you ship *oil*, not oil and water.

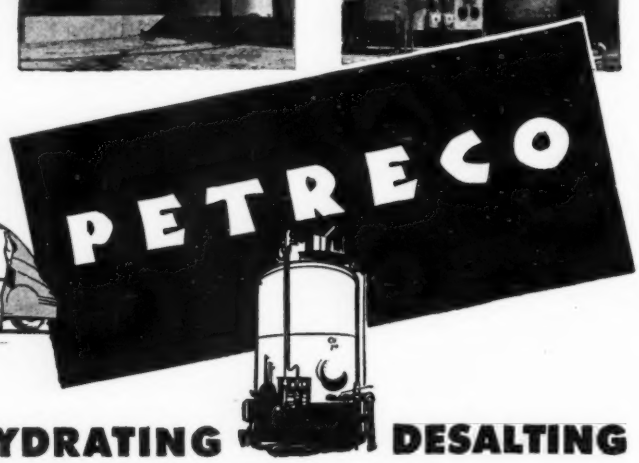


REFINING



The low B. S. and W. content of Petreco-processed crudes assures a minimum of moisture in the crude charge. This eliminates many refining complications due to poorly conditioned crudes.

COMPLETE OIL STATE COVERAGE WITH PETRECO PROCESSES



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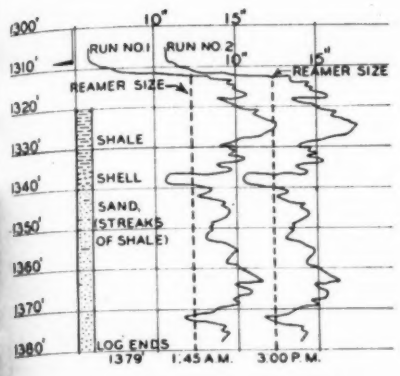


Fig. 5. Filter cake vs. time; oil-base fluid

ing its production history, the well made varying amounts of sand. Recently, the liner was pulled and a caliper was run as shown. From the log it is seen that in two cases the shale had broken away above a sand cavity and presumably back-filled the annulus opposite the sand bed.

The authors have only two suggestions to prevent such packing of shale behind liners. In those areas containing shale that is not affected by oil, the wells should be drilled in with crude oil or oil-base drilling fluid. In areas where shale is affected by oil, either drilling oil or formational fluid, the best solution appears to be a conventionally gravel-packed liner regardless of sand conditions.

Solid cementing and selective gun-perforating may also solve the problem, but this method is believed applicable in low pressure zones only in selected areas.

Other drilling fluids. Besides ordinary water-base mud and various types of oil-base drilling fluid, two other drilling fluids can be mentioned. Some operators prefer to drill in or freshly wallscrape low pressure zones with the drilling fluid made from bentonite. This fluid makes a very lightweight mud that reduces the hydrostatic pressure against the zone and is believed to form a soft, easily removed cake. However, some laboratory experiments have shown that a bentonitic gel cake on sands of high permeability may be inadequate to prevent actual penetration of the gel into the zone. Whether or not this is detrimental, is not known.

A second completion fluid very recently tried consists of water-base mud of a high alkaline value treated with hydrolized starch. This combination is said to have the effect of greatly lowering the water loss and forming a very thin cake, thus both decreasing the seepage into the sands of drilling water and eliminating any harmful effect due to the presence of a thick tough cake. It may have promise, especially if salt water is used as the mixing medium.

Effect of various fluids on production. Considerable data indicate that the presence of water, particularly fresh water, is detrimental to the effective permeability to oil of many sands, especially those of low values. This condition, of course, would seriously impair production from low pressure zones. Therefore, it would seem logical that such zones should be drilled with some fluid other than water-base muds. Wells drilled with these other drilling fluids should therefore show improvement in production over those drilled with water-base mud. However, it is extremely difficult to prove this in the field. In most fields in California, and particularly in the San Joaquin Valley, the low pressure zones vary greatly in sand content, permeability and saturation over short distances. Moreover, in the operator's desire to obtain the best possible completion at the cheapest cost, it is difficult to impress him with the value of any controlled research. For example, if a good completion is obtained with bentonitic gel, oil-base, crude oil, or plain mud, then there is no reason in the operator's opinion to change to some other mud for any later well, for which he cannot be blamed.

Despite these difficulties of control, there are some field data that offer a comparison of the effect of different fluids on production.

Oil-base completions. In the West Coalinga oil field, several wells were drilled in one area to the Light Oil zone and to the Tar zone with various types of drilling fluids. In two wells, the zone was drilled and the well completed with water-base mud. Four wells were drilled and completed with oil-base fluid. Five wells were drilled with water-base mud and completed with one or another type of oil-base fluid. Table I shows the comparison of initial

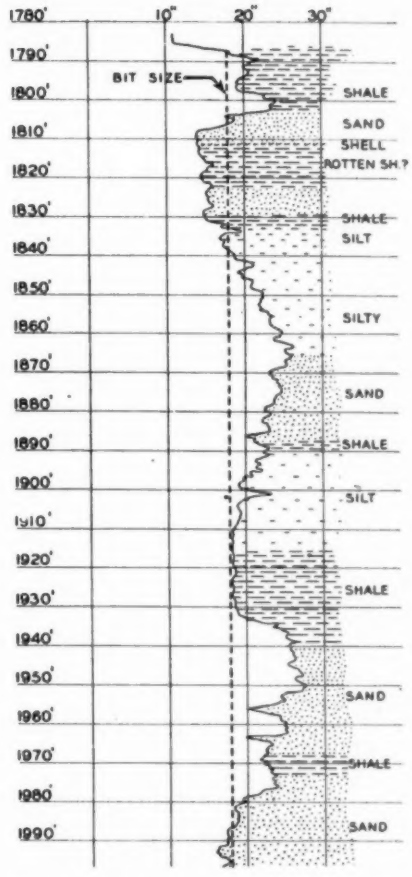


Fig. 6. Showing condition of hole after pulling liner from producing well

production and settled production in the second month. Due to the varying amounts of sand thickness, production rates were reduced to barrels per foot of sand penetrated. Sand counts were made as carefully as possible to include only that sand considered permeable by determination from core analysis, by sight, or in the case of lost cores, from the self-potential curve of the electric log.

As seen from Table I, the poorest productivity occurs in those wells which were drilled and completed with

TABLE I

Production comparison—water-base vs. oil-base drilling fluid

Well	Perf.	West Side Coalinga—Light oil zone							Type fluid	
		Sand count, ft.	Gross I. P., bbl.	Bbl. per ft. sand	Avg. bbl. per day 2nd mo., gross	Bbl. per ft. sand	Avg. bbl. per day 2nd mo., net	Bbl. per ft. sand	Drill in	Completion
1	25 ga.	10	32	3.2	30	3.0	27.5	2.7	W.B.	W.B.
2	30 ga.	14	70	5.0	55	3.9	49	3.5	O.B.	O.B.
3	30 ga.	29	128	4.4	106	3.7	104	3.6	O.B.	O.B.
4	30 ga.	17	83	4.9	65	3.8	50	3.0	O.B.	O.B.
5	40 ga.	15	51	3.4	46	3.1	40	2.7	O.B.	O.B.
6	40 ga.	14	55	3.9	48	3.4	20	1.4	W.B.	O.B.
7	G.P.—¼ in.	28	132	4.7	124	4.4	104	3.6	W.B.	O.B.
	Tar zone									
8	G.P.—¼ in.	26	65	2.5	65	2.5	54	2.1	W.B.	O.B.
9	G.P.—¼ in.	22	30	1.3	30	1.3	25	1.1	W.B.	O.B.
10	G.P.—¼ in.	27	44	1.6	44	1.6	30	1.1	W.B.	O.B.
11	G.P.—¼ in.	25	27	1.1	24	0.9	18	0.7	W.B.	W.B.

W.B.—Water-base mud. O.B.—Oil-base mud.

TABLE 2

Cost of special fluids—dollars per bbl.

	Initial	Recovery	Net	Trucking and facil.	Mixing and wash.	Total	Savings on bailing	Net	Remarks
Type A oil base....	$7.00	$4.60	$2.40	$0.59*	$1.00	$3.99	$0.92*	$3.07	Wash with oil to recover
Type B oil base....	5.00	3.25	1.75	0.59	1.00	3.34	0.92	2.42	Wash with oil to recover
Bentonitic gel.....	0.35	....	0.35	....	0.62	0.97	....	0.97	
Special chemically treated fluid.....	0.70	....	0.70	....	0.25	0.95	....	0.95	
Hole mud.....	....	....	....	....	....	....	....	....	

Additions and treatment of cement cutting=0.50.

*Based on volumes for 2200-ft., 6⅝ in. hole.

water-base mud. In the Light Oil zone, the water-base well had the initial production of 3.2 bbl. per ft. of sand as against 5 bbl. per ft. of sand from the best well drilled and completed with oil-base mud. In the Tar zone, water-base initial production was 1.1 bbl. per ft. of sand. The best oil-base completion was 2.5 bbl. per ft. of sand. In comparing wells in the Light Oil zone, there seems to be little advantage in drilling through the pay zone with oil-base mud over drilling through with water-base mud, but considerable advantage in completing with oil-base mud.

While it is felt that to draw conclusions on results involving a comparison of but two wells out of a group of 11 would be presumptious, nevertheless, the advantage of oil-base mud is indicated.

Crude oil completions. Many wells have been successfully completed by using crude oil as circulating fluid and evidently its use is advantageous compared with the use of water-base mud. This seems to be particularly true when using perforation sizes other than very fine. When using fine mesh liners, however, some fields experience indicates that it is difficult or impossible to remove by thorough washing the oil-mud-water emulsion formed when drilling or wallscraping. This mixture may be so impervious as to actually shut off formation water. In a well of doubtful oil content drilled at Lost Hills, a 40-mesh liner was set after wallscraping and washing with oil. When the well was bailed dry, the liner was washed with distillate and the well completed for 15 bbl. per day of salt water. The liner was then gun-perforated with half-inch holes and the well again recompleted for 130 bbl. per day of water.

In other areas, however, it is reported the use of crude oil has shown considerable increase in the initial and settled production over wells completed with water-base fluids.

One of the reasons that crude oil can be successfully used in certain fields is because of the low bottom hole temperature. The relationship between this temperature and the solubility of shale in crude oil is not fully understood but from the effect of crude oil at high temperatures on shale it is suspected that straight crude oil cannot be used in areas where bottom hole temperatures are high.

Special drilling fluid completions. Comparative data are unavailable by which conclusions can be drawn on the effect of using bentonitic gel muds or chemically treated muds for completion over the use of ordinary water-base mud.

For the chemically treated mud, the best that can be said is that it apparently has no detrimental effect as compared with wells completed with normal water-base fluid. One well drilled in South Belridge was located in the middle of a group of wells completed in the normal manner with the usual water-base mud. This well was drilled to the top of the zone with water-base mud, the casing set and the zone drilled with an excessively alkaline fluid treated with hydrolized starch. Initial and subsequent production is comparable to the average of the wells drilled with water-base fluid.

Costs of use of drilling fluids. Table 2 shows a comparison of the cost of using two types of oil-base drilling fluid, bentonitic gel fluids, chemically treated fluids, and ordinary water-base mud. These are calculated on a per barrel basis and on volumes necessary for 2200 ft. of 6⅝-in hole. They include trucking and other facilities wherever necessary, mixing time, and wash oil necessary to recover oil-base drilling fluid. Cost of oil-base mud is not calculated on initial cost but is based on recovery of, at least, 65 per cent of the total volume used. Very frequently 80 to 90 per cent is recoverable, but occasionally 50 per cent is lost. Therefore, the 65 per cent figure is used as a conservative average.

Conclusions. It is an obvious fact that, of the many shallow wells drilled in California in low pressure zones, most must be regarded as successful completions, though drilled without particular attention to the type of drilling fluid used.

Whether or not the completions would have been larger if drilled with fluids other than standard water-base mud is difficult to determine, but there is considerable unassociated evidence that this is the case.

From the data presented, it may be concluded that:

1. There is definite proof of seepage of water from the ordinary drilling mud into the sand bodies encountered in the hole.

2. The seepage of fresh water into the producing sands should be kept at a minimum or eliminated entirely to insure maximum productivity. There is definite evidence that the use of oil-base drilling fluid provides greater initial and settled production.

3. The use of oil in areas where shales are present, that are apt to slough on contact with oil, should be avoided as it may be harmful for the maintenance of sustained production. Sloughing, started by drilling oil, may be continuously aggravated by formation oil.

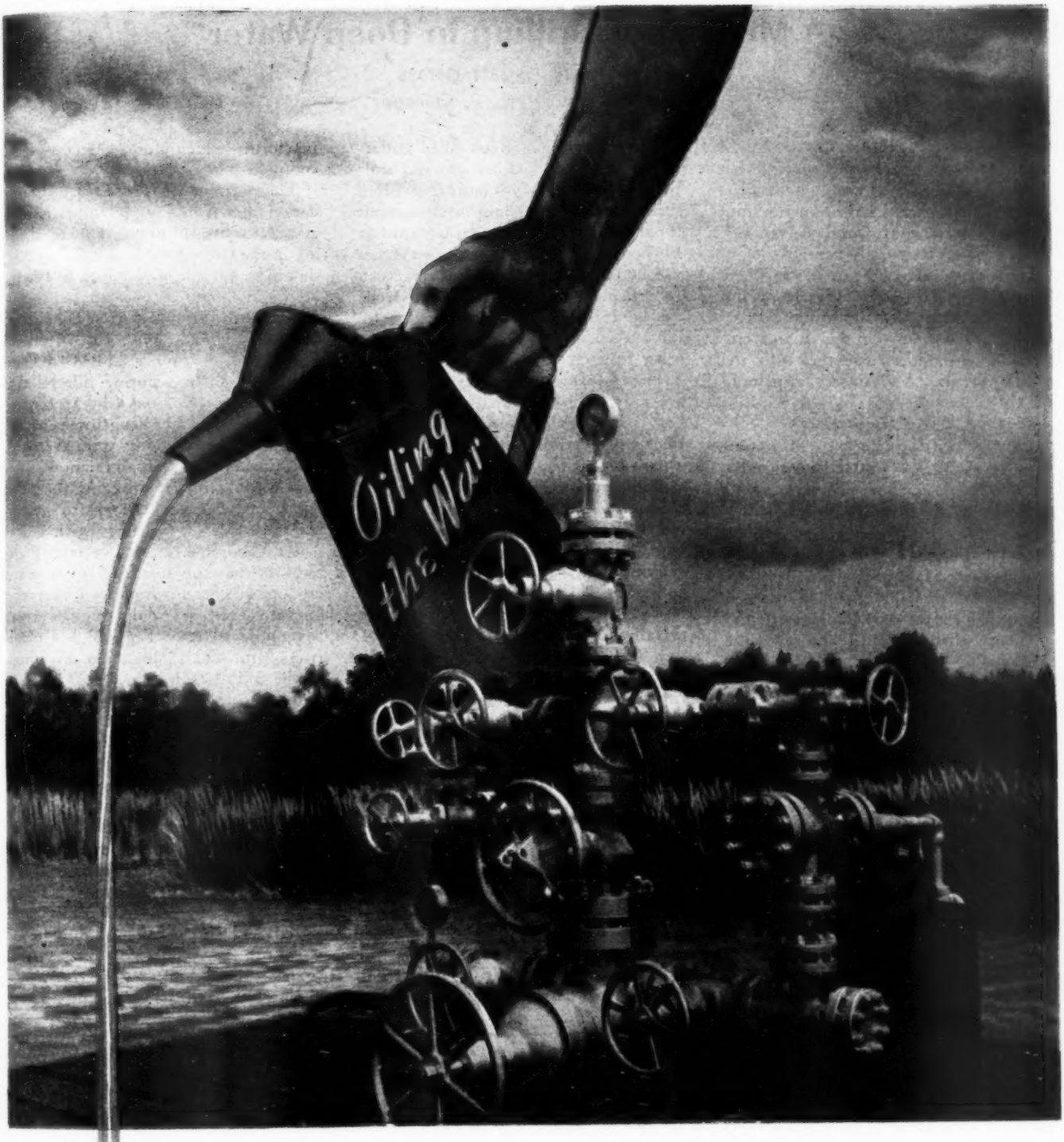
4. The favorable results of fluids other than water-base muds are indicated by many examples of good well completions, but the final evaluation must be deferred for further study.

☆ ☆ ☆

Hydraulics of Mud-Circulating Systems

Under the above heading Wesley W. Moore of Tulsa, Oklahoma, presented a paper before the American Petroleum Institute at the Chicago, Illinois, meeting last Fall. His discussion did not relate to mud control nor mud conditioning, but dealt with a preliminary analysis of the problem of circulating an average rotary drilling mud down to and back up from the bottom of the well bore in such volume and at such velocity as to effectively remove drill cuttings from the face of the formation being contacted by the drill bit and to transport such cuttings to the surface where they can be deposited.

The useful work accomplished by the circulating mud stream is normally very small in relation to the energy expended. Much of the hydraulic energy, supplied by the slush pump, is consumed by friction head within the drill pipe; whereas no useful work is accomplished by the mud stream until after it has left the drill bit. In most instances the overall mechanical efficiency of the mud-circulating system can be improved by closer attention to the relationship of hole diameter, drill pipe size, and slush pump capacity, were his conclusions.



America's great Oil Industry has been called on to produce oil in greater quantities than ever before in the history of the world . . . and a recently completed well is symbolic of the Producing Industry's record-breaking achievements in meeting this challenge. During the past two years, every previous production record has been broken in the task of supplying the vast quantities of petroleum products needed to *oil the war.*

In support of the current aggressive search for new producing horizons, Hughes Tool Company is on the job twenty-four hours a day . . . producing Rock Bits, Core Bits, Tool Joints, and other specialized tools needed to *keep 'em drilling.*

Hughes Tool Company **Houston, Texas**

A Method of Drilling in Deep Water*

By HENRY EMMETT GROSS
PAW, District No. 2, Chicago

INTRODUCTION. New sources of petroleum and natural gas are beneath large bodies of water such as the Great Lakes, except Lake Superior, and ultimately the continental shelves.

It is now particularly desirable to exploit the Great Lakes because: (1) There is an acute shortage of petroleum and natural gas in the surrounding area; (2) the Lakes are far inland and safe from enemy raiders, (3) they offer the shallowest possible sources remaining in this country, and (4) the water is not as rough as in the open seas.

The one discouraging condition, floating ice in the winter, should offer no problem.

In the Great Lakes, four places appear attractive for prospecting for oil: (1) The western end of Lake Erie, (2) the northwest half of Saginaw Bay, (3) the east side of Lake Michigan between Benton Harbor and Ludington, and (4) the shallow south end of Lake Huron.

The title to submerged lands beneath navigable waters of the United States is owned by the various states. The boundaries are established. Leasing would have to be from the states, but before mineral could be extracted, approval must be obtained from the War Department.

Methods of development. The shallower parts of such small bodies of water as the western end of Lake Erie, Lake St. Clair or Saginaw Bay, could be prospected and drilled by the submersible barge of Giliasso,[1] one of which can keep a single string of tools running for about eight months of the year. Some of the deepest wells have been drilled from submersible barges in the bays and bayous of the Gulf Coast. The Cedar Point field in Galveston Bay was developed by barge drilling. This method at present is limited to water less than 10 ft. deep, and is not suitable in open water like that offshore in the Gulf of Mexico or the Pacific Ocean.

Conventional rigid foundations are unsuitable economically, although widely demonstrated as capable of withstanding rough seas in 10 to 40 ft. of water. The cost of simple piling foundations varies from $5000 in the shallower waters of Lake Maracaibo and $14,000 in the shallow protected waters of Terrebonne Bay, Louisiana, to $75,000 in 40 ft. of open water in the Pacific Ocean at Rincon, California, and all of these foundations are suitable for 7000-ft. drilling.[2a] Rock-filled cofferdams, concrete-filled caissons and multileg foundations of concrete-filled sheet-pile cylinders comprise the various types of lighthouse foundations used at Elwood, California. These cost from $35,000 to $90,000 and are satisfactory for the deepest drilling. Many wells can be drilled from one foundation by directional drilling. The design and other features of these foundations are covered in detail in a thesis by Gross.[2b] Specially precast sectional caissons[3] have been used for leg corners of foundations in 100 ft. of water in Lake Maracaibo.

Barge pile drivers cannot be used in the open ocean because even on a glassy sea the ground swells are about 6 ft. high, and these undulations cause such swaying of the barge that piles cannot be driven. To oversome this, Roberts[4] fabricated a tower 20 ft. square and 60 ft. tall, which was erected by using four steel H-beams as the vertical legs, and making the structure rigid by suitable sway bracing. Fabrication was performed on the end of a pier that was near the location of the proposed well. Four such units were built and a derrick barge then picked up these towers bodily and deposited them adjacently at the well location, so as to form a tower 45 ft. square rising 20 ft. above the sea. After plumbing, the framework was decked and braced to form a landing from which to begin construction. A knocked down pile driver and supplies were unloaded upon this platform, and after erection the driver proceeded with the construction of the drilling platform, which cost $75,000 when completed.

The portable buoyant marine foundation shown in Figs. 1 and 2 is suggested for the 1500 to 3500-ft. drilling in the Great Lakes. This foundation should be suitable in water up to 100 ft. deep and should be constructed to offer maximum buoyancy. The cost should be about $3000 for 30 ft. of water. Buoyant timber skids *A* are built on the beach by securing side by side four pressure-creosoted 4 by 16 forties. Staggering could be lengthwise to afford a sufficiently long skid. A toe *B* is secured on the front to facilitate subsequent dragging. If dragging for miles is anticipated it would be wise to sheathe the underside of the skids with boiler plates. Creosoted timber pyramids *E* are built on the skids to afford ample bearing surface. Steel bed plates *F* keep the buoyant legs *G* from piercing the wood pyramids. Buoyant legs *G* are made from 7-in. o.d. 17-lb. range-1 casing. In the end of each joint a steel plate is welded, so that the pipe will be buoyant in water. The joints are screwed end to end to form the leg. Buoyant horizontal compression members *H* are made from the same type of casing and the ends are welded to the vertical members. Steel sway bracing *I* is made preferably from rods at least 1⅛ in. in diameter. Timber caps or sills *K* are 14 by 14 sixties and joists or stringers *L* are 4 by 16 forties. Decking *M* is composed of 3 by 12 timbers. A 60,000-lb. maximum permissible column load per leg, less 11,000 lb. per leg for the wooden platform with the remaining 49,000

Figs. 1 and 2. Portable buoyant marine foundation. A—Buoyant timber skids. B—Toe of skid. C—Sea floor. E—Timber pyramids. F—Steel bed plates. G—Buoyant legs (air-filled pipe). H—Buoyant horizontal compression members (air-filled pipe). I—Steel sway bracing. J—Sea level. K—Timber caps or sills. L—Timber joists or stringers. M—Timber decking. N—Derrick leg. O—Conductor pipe

Fig. 1

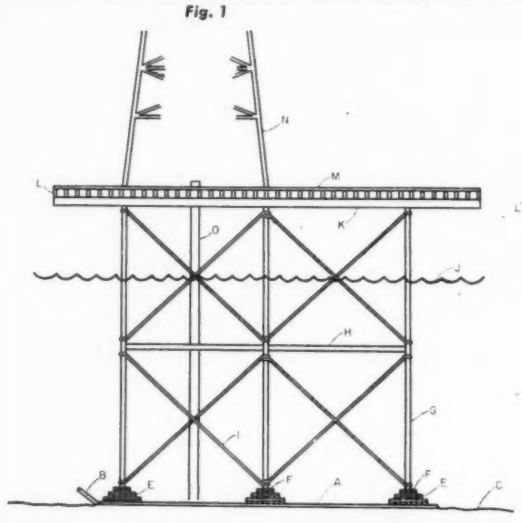
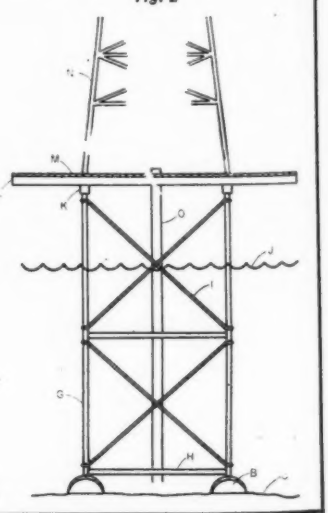
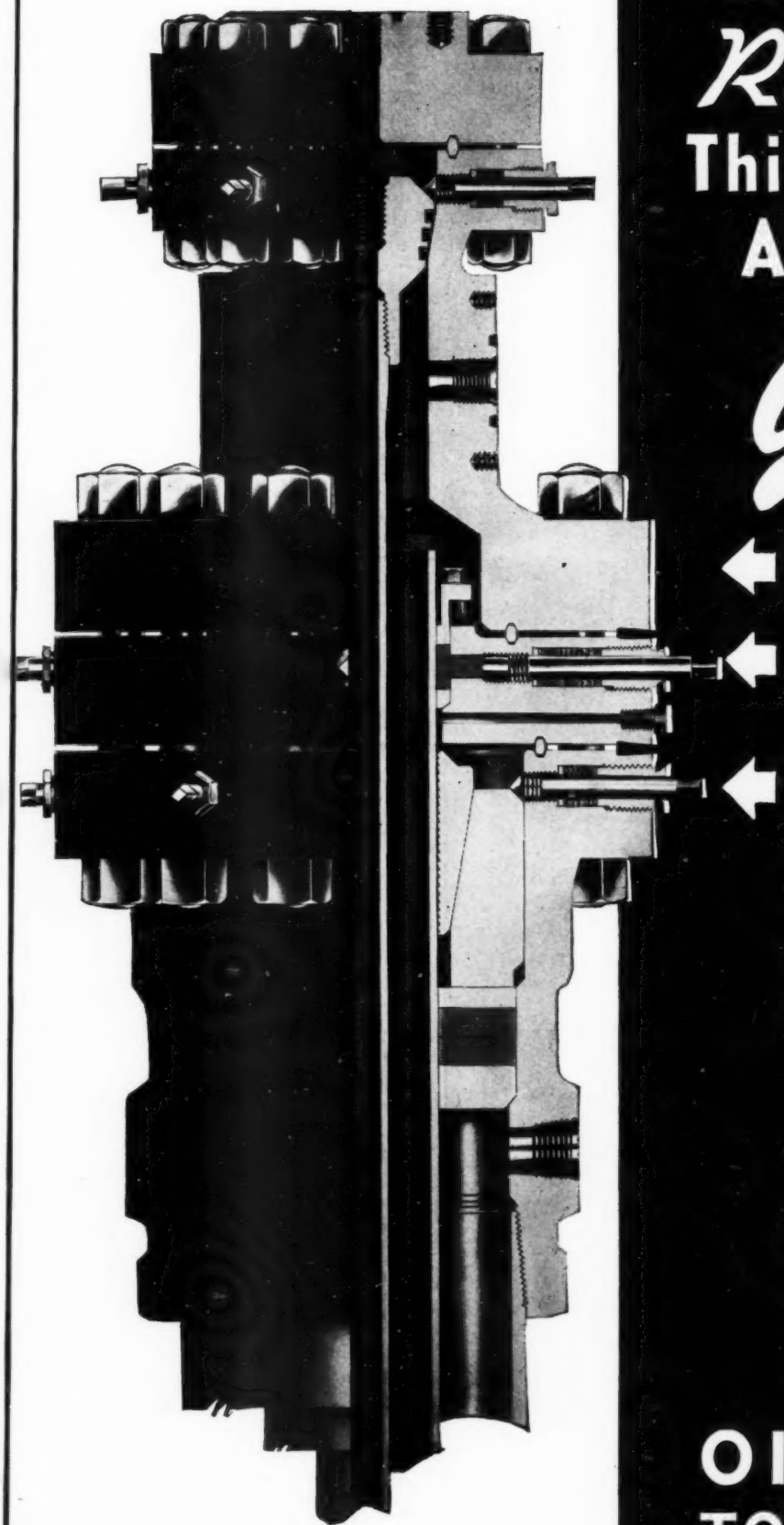


Fig. 2



*Presented before American Institute of Mining and Metallurgical Engineers, Los Angeles, California, October, 1943.



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lb. per leg, or approximately 200,000 lb. attributable to the derrick, should be ample to carry the ordinary working loads for up to 3500-ft. cable-tool drilling in the Great Lakes. The drive pipe O could be made to support its share of the derrick floor when running heavy strings.

After the portable marine foundation has been towed into place, a mixture of sand and gravel is dumped on each skid with a tremie pipe to a depth of about 10 ft. This loading is to prevent movement or overturn in rough weather.

Drive pipe usually is driven through the glacial till, in this case marked as conductor pipe O. Once this pipe is carried through the drift to its objective, a casing clamp can be placed thereon near the lake floor and the corners of the derrick turn-buckled to this, giving added stability during storms. When long strings of pipe are to be run the turn-buckles could be loosened to prevent overloading the foundation. In the event of a dry hole the portable marine foundation (Figs. 1 and 2) could be moved to another location. In calmer weather small barges could be used, one on each side of the foundation, and after jetting away from the skids the sand and gravel covering and removing any other tiedowns to the lake floor, the foundation, derrick and all, could be raised and floated to a new drilling site.

The marine foundation and method of construction of Gross[5] is set forth in Figs. 3 through 8. This foundation was designed to completely exploit the continental shelves that would require development in as much as 600 ft. of water. The cost would be too great for the low oil recoveries per well that would be obtained in the Great Lakes unless the foundation could be moved from well site to well site as wells are depleted, which is logical.

Figs. 3-8. Marine foundation and method of construction. A—Buoyant skids (fabricated from air-filled pipe). B—Buoyant legs (air-filled pipe). C—Buoyant horizontal compression members (air-filled pipe). D—Steel sway bracing. E—Diagonal horizontal sway bracing. F—24-in. I-beam. G—24-in. I-beam. H—Railroad car wheels. I—Conductor pipe. J—Skid member (air-filled pipe). K—Metal plate. L—Anchorage pipe. M—Casinghead. N—Drilling platform

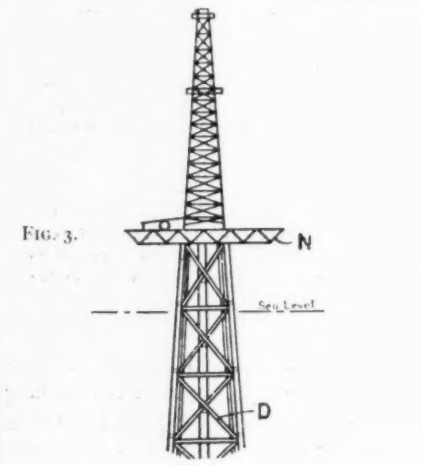
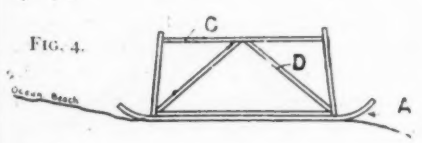


FIG. 3.



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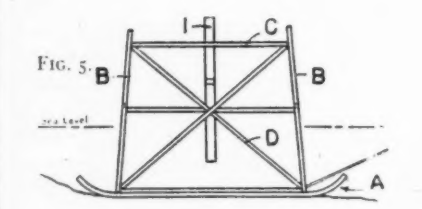
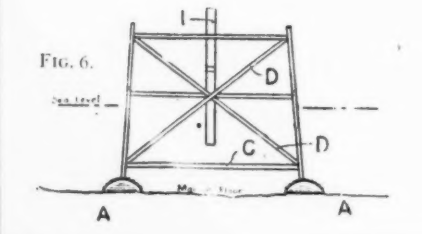


FIG. 5.



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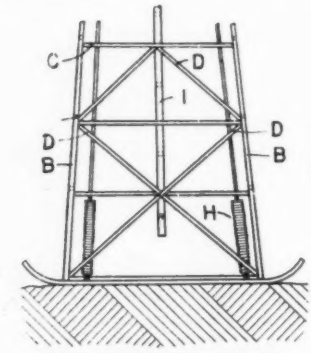

FIG. 3a.

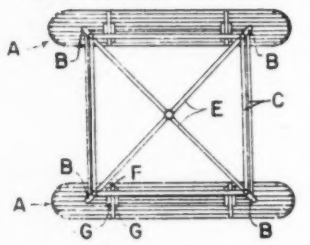

FIG. 7.

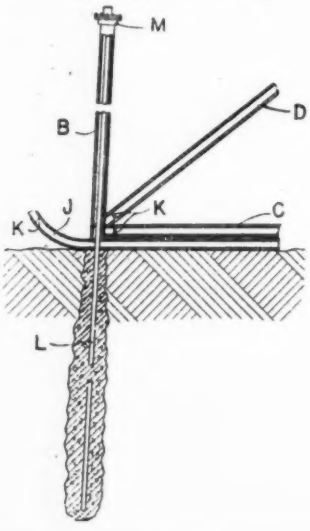

FIG. 8

To construct this foundation, buoyant skids *A* are fabricated on the beach from air-filled pipes, such as 18⅝ o. d., 96½ lb. per ft. casing, which has a net buoyancy of 25½ lb. per ft. in sea water. Such skids are long enough and wide enough to give ample stability against overturn of the tower or settling from drilling loads. Following the leg taper of a 122-ft. A.P.I. derrick having a 24-ft. square base, in 600 ft. of water, the distance between foundation legs at the sea floor would be about 110 ft. and the length of skid required about 160 ft. If the foundation must be dragged for miles to the well site, the bottoms of the skids would be covered with boiler plate. The first section of the tower is erected on the beach as shown in Fig. 4. The compression members are composed of 18⅝-in. o.d. 96½-lb. per ft. casing, each joint having plates welded near the ends to make it an individual buoyant unit. Where the ends of pipe must be cut at other than right angles, this is done by means of a template. Sway bracing may be of solid 2-in. tie rods. The first section of conductor pipe *I* is secured in the center of the first section of tower and suspended 10 or 15 ft. off bottom, so that it will not hit obstructions on the sea floor during subsequent dragging operations. Mats composed of 24-in. I-beams *F* and *G* are secured on the skids *A* as shown in the plan view of Fig. 7. On these mats means are provided to carry a concentrated load of railroad-car wheels *H* to furnish stability to the tower.

As soon as the first section is built, the unit is towed to sea until only a few feet emerge. The second section is built thereon as shown in Fig. 5 and the foundation is towed farther out to sea for erection of the third section. The process is repeated until the drilling site is reached. The base is loaded with railroad-car wheels and the skids can be covered with a sand and gravel mixture to a depth of 10 or 15 ft. to afford a stable foundation. If the foundation is to remain permanently, the legs may be drilled through with a portable rotary and the drill stem may proceed a couple of hundred feet into the sea floor and be cemented as is shown in Fig. 8.

If the sea floor at the drilling site were sloping, a hydraulic leveling device[6] would be mounted on the legs while the first section was being constructed on the beach. As soon as the foundation was on its location it would be plumbed by these hydraulic means and maintained in vertical position until a sufficient amount of gravel could

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be filled in under the skids to provide a permanent base.

After the tower is secured in place, drilling platform *N* (Fig. 3) is built thereon. It is steel trusswork and must be built high enough above sea level to clear the largest storm waves. The bottom of conductor pipe *I* is considerably above the sea floor and so a surface string either must be driven into the earth to a satisfactory depth by cable tools, or drilled into it by rotary.

A type of portable marine foundation[7] for use in depths of water from 10 to 100 ft. is shown in Figs. 9 through 11. A pontoon *I* having a square base and top and vertical sides is built in a shallow protected bay or harbor. Vertically through the center of this pontoon is an opening through which drilling operations may be performed. About this pontoon is built spread footing *B* composed of horizontal sills *C*, the lower-most tower section *D*, and the diagonal braces *F*. Hydraulic anchorages *K*, if their use is desired, are secured to the bottom end of the tower legs. The angle-iron legs *E* act as guides or trackways for vertical movement of the pontoon *I* and tower A with respect to each other. In order to cover the heads of the bolts through the vertical angle-iron legs and make movement of the pontoon with respect to the trackway smooth, it is lined with wood and the vertical edges of the pontoon are correspondingly covered. The use of air-filled oil drums about the outer edge of the spread footing may add to the stability during the initial stages of construction.

After the first section is in place, the assembly is towed to deeper water and the second section is erected. Weights such as pig iron may be loaded on the spread footing, water let into the oil drums and the tower lowered about the central pontoon. The oil drums then are cut loose. The structure is towed to deeper water and a third section of the tower is erected. The process is repeated until the drilling site is reached and the tower is tall enough to land on the bottom of the sea, where the hydraulic anchorages *K* are driven into the earth. The pontoon is filled with sufficient water to permit lowering it 10 to 20 ft. below water level and securing it at this point. The spread footing *B* is covered sufficiently with a sand and gravel mixture to hold it firmly in place. The rig platform *N* and derrick *R* then are built and the drilling machinery installed. The pontoon now has the water pumped out and replaced by air, and in this manner is able to take much of the load off sections of the tower below the pontoon. This should be of much assistance where the depth of water is 100 ft. or more.

The foundations shown in Figs. 1 through 11 are open-type foundations and offer a minimum of cross-sectional area to the devastating cusping waves and high winds, whereas conventional light-house-type foundations have large exposed areas.

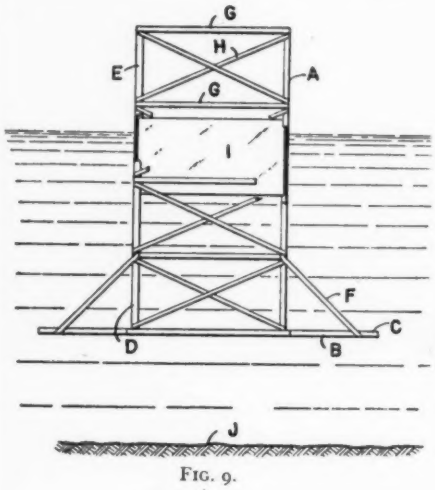


FIG. 9.

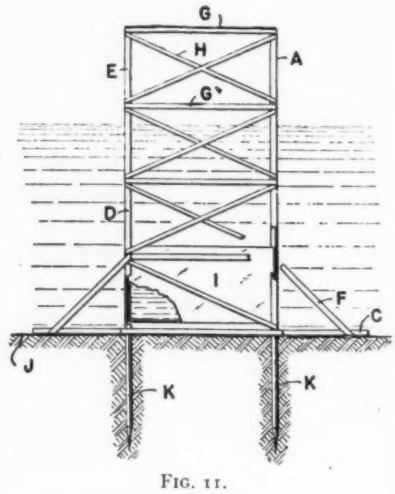


FIG. 11.

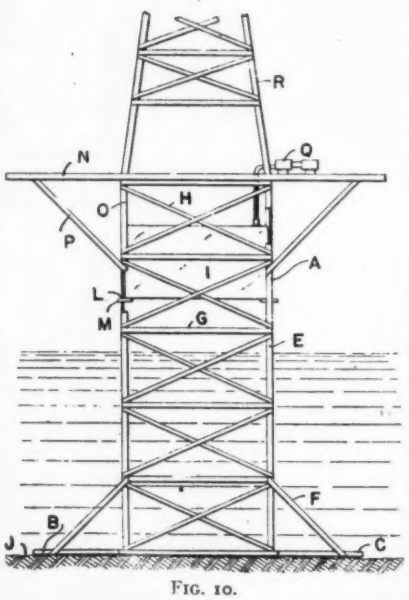


FIG. 10.

Figs. 9-11. Portable marine foundation for use in depths of water from 10 to 100 ft.

A—Marine foundation. B—Spread footing. C—Horizontal sills or beams. D—Tower sections. E—Angle-iron legs. F—Diagonal braces. G—Horizontal compression members. H—Sway bracing. I—Pontoon. J—Sea floor. K—Hydraulic anchorage. L—Stop bar opening. M—Stop bar. N—Rig platform. O—Upper section of foundation. P—Braces. Q—Pump. R—Derrick

TABLE 1

Height of Waves*

Place of observation	Length of fetch, nautical miles	Observed height of waves, ft.	Calculated height, ft.	
			a	*b*
Scappa Flow, Jutland, Ger.	1.0	4.0	1.5	3.0
Firth of Forth	1.3	1.8	1.8	3.2
Lough Foyle	7.5	4.0	4.1	4.96
Clyde	9.0	4.0	4.5	5.25
Colonsay	9.0	5.0	4.5	5.25
Lough Foyle	11.0	5.0	5.0	5.7
Anstruther	24.0	6.5	7.5	7.7
Lake of Geneva	30.0	8.2	8.2	8.37
Buckie	40.0	8.0	9.5	
Douglas I. O. M.	65.0	10.1	12.0	
Kingstown	114.0	15.0	16.0	
Sunderland	165.0	15.0	19.3	
Peterhead	400.0	22.6	30.0	

*After Brysson Cunningham.[8]

Table 1 shows the observed heights of waves compared with the length of open sea to generate them. Table 2

TABLE 2

Pressure for breaking waves*

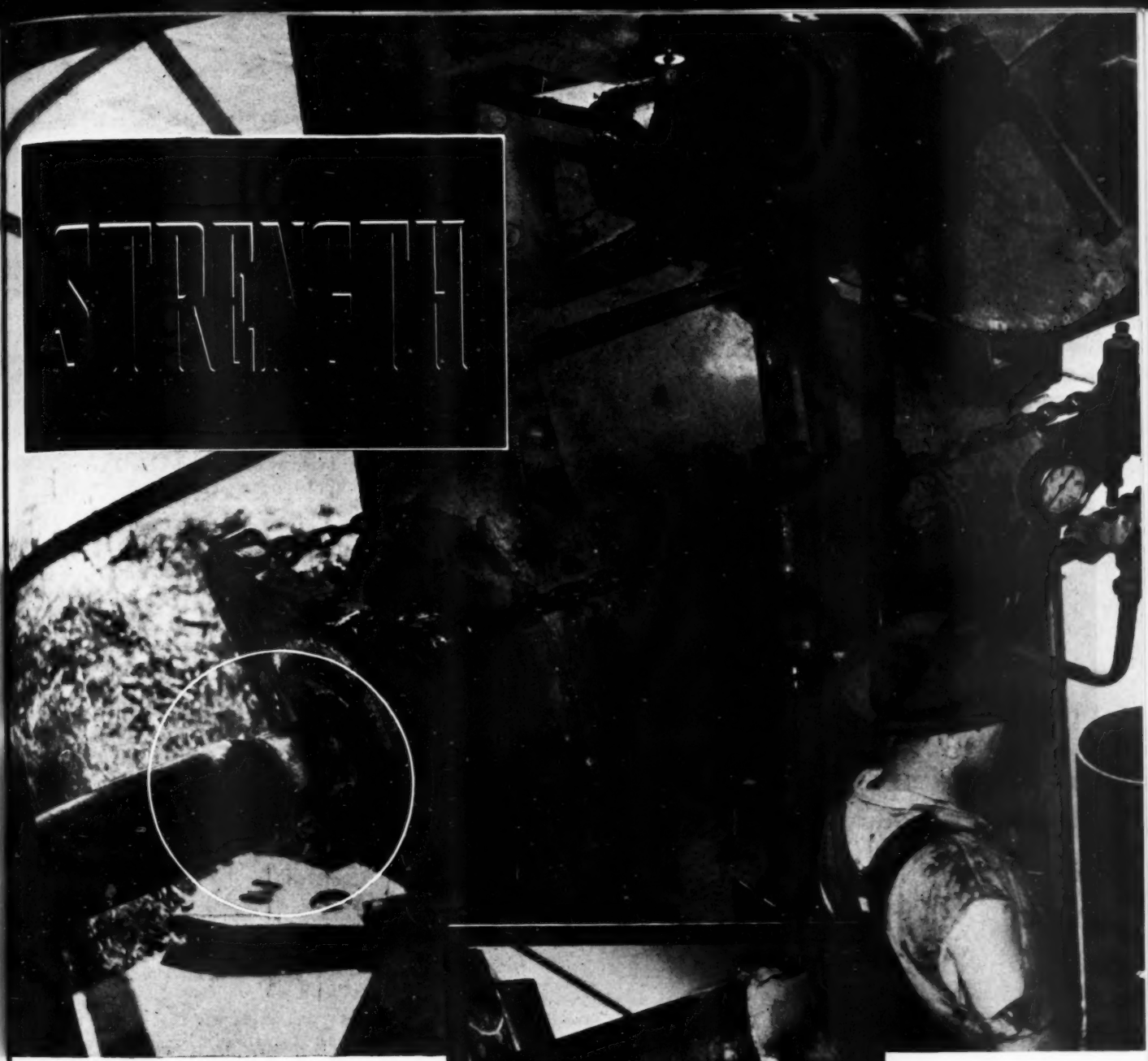
Height, ft.	Velocity, ft. per sec.	Pressure	
		Pounds per sq. ft.	Tons per sq. ft.
10	22	1,024	0.45
20	32	2,048	0.91
30	39	3,072	1.37
40	45	4,096	1.83
50	51	5,120	2.29
60	55	6,144	2.74
70	60	7,168	3.20
80	64	8,192	3.65
90	68	9,216	4.11
100	71	10,240	4.58

*After Brysson Cunningham.[8]

shows the pressure to be expected from breaking waves. Waves higher than 20 ft. are not to be expected on Lakes Michigan, Huron, or Erie. Knowing the possible pressures, the marine foundation can be designed accordingly. These tables are after Brysson Cunningham.[8]

Floe ice. The principal hazard to drilling in the Great Lakes is ice. In the winter floe ice can be seen for miles out from shore but usually it collects near the shore and the deep-water portions of the Lakes are open. To overcome the hazards of ice in water less than 100 ft. deep, the following plans are suggested.

For gas development, wells are completed from portable foundations in such a manner that the well head and pressure gauges are just above the lake



Note (in white circle) Bakelite nose begins to collapse. Note (at left) nose collapsed completely at 320,000 pounds.

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Numerous shoes were tested and this was the average test. It indicated a strength 30% greater than concrete nosed shoes similarly tested.

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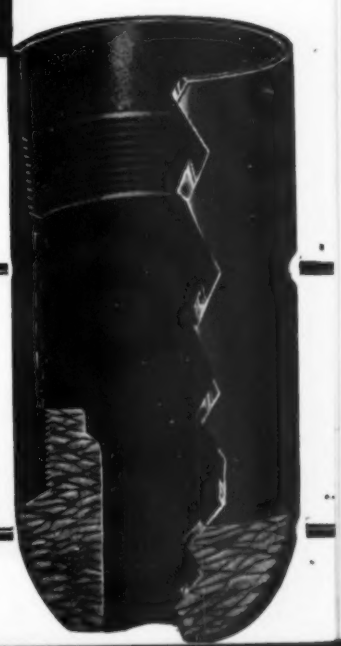

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floor and visible from a glass bottom boat. The portable foundation is removed after the well is completed. Lead lines are laid on the sea floor to shore if the field is not far out, but if it is miles out a rock-filled cofferdam may be used as a central collecting point and compressor station, and the gas piped to shore from this point. The permanence of the Chicago water intakes would indicate that rock-filled cofferdams would not be destroyed by floe ice.

Should the gas wells tend to water up, provisions could be made for keeping them unwatered. To do this a return line would be laid from the compressor plant on the rock-filled cofferdam to the bradenhead of the well. Noncorrosive kick-off valves would be placed at proper intervals down the tubing. Whenever the well watered up, it could be unloaded by injecting air or some of the gas from other wells through the return line and down the annulus in the same manner that oil wells are unloaded by means of kick-off valves in various parts of Texas.

Methods of production. An oil field could be developed in a manner similar to a gas field, but be made to flow to depletion on artificial water drive. The oil field would be drilled up on a water-input pattern with the necessary coring and capacity testing of wells but without production. A rock-filled cofferdam would be built in the center of the field and a water-treating plant and oil-flow tanks built thereon. Water lines would be laid to the input wells and water pumped into them until several hundred pounds injection pressure was required. Then oil wells would be drilled between the input wells and made to flow their production at restricted rates until depletion. In this manner, primary and secondary oil would be recovered simultaneously by a secondary recovery method of flowing production by an induced water flood. No permanent foundations would be needed over the oil wells, ice would be no hazard, production could be pumped through a submarine oil line directly to shore and in many fields recovery would be greater. This would be true particularly in the gas-drive fields.

Corrosion. The problem of corrosion of steel foundations is not great. The steel H-beam piles at Elwood and Rincon, California, have lasted for 13 or 14 years and these fields will produce for many more years. H-beams are affected by corrosion and sand cutting from all sides, whereas pipe would be damaged on the outside only. It would appear that if protective coatings were applied to the pipe as on pipe lines, and if cathodic protection were used, corrosion could be minimized.

Safety measures. Fog horns and lights must be supplied on marine foundations in navigable waters to prevent collision with ships.

Preceding the tug that tows a foundation, a small vessel may take soundings with a Halliburton line to see that there are no obstructions in the path of the tow. The Halliburton line also may be used to find level locations for well sites.

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Oil Field Operation With Cooperative Engineering Committees*

By V. E. COTTINGHAM, *Chairman*
North Basin Pools Engineering Committee

INTRODUCTION. A great deal has been said about the unitization of oil pools. This subject implies the voluntary unifying of ownerships, which may include not only the leasehold interests but may also include royalty interests. Under unit operation the oil pool, as distinguished from the individual lease, becomes the unit of operation. The engineering and statistical data for this type of operation are assembled and compiled by a single organization for the field as a whole. The completeness of these data and the beneficial use to which they are put depends on the unit operator.

The benefits of cooperative unitization are considered by most engineers to be in the interest of both economy and a greater ultimate recovery. The question naturally arises as to why there are so few unitized oil fields. (Texas has only one). Where there is a large diversified ownership, it may be quite easy to devise a unit plan of operation down to the point where the division of interests are considered. At this point the human equation enters the picture. This human factor is largely responsible for there being so few voluntary unitized oil fields in the nation. In my opinion, present day knowledge of underground values is not certain enough to justify complete compulsory pooling. Even though unitization may be admitted to be a good thing in general, companies and individuals alike have been reluctant to relinquish operating control of their properties to someone else.

I have been invited here today to tell you about another type of voluntary cooperative work being carried on by oil producers through engineering committees. In those fields in which cooperative engineering committees operate, the engineering and statistical data are assembled and compiled for the field as a unit. The completeness of the data depends on the policy of the participating operators, and the beneficial use to which the data is put, depends largely on the individual producer.

Very little has been said concerning this kind of cooperative enterprise. There are seven cooperative engineering committees or associations in Texas. While this number is not large, they are operative in fields that contain approximately 50 per cent of the estimated oil reserves of the state. All of the oil fields of New Mexico are served by a single engineering committee. However, the strictly engineering work is confined principally to the 29 fields in Lea County. I have not made any attempt to acquire data on engineering committees in oil fields of other states.

Engineering Committees in General. The duties of cooperative engineering committees, or operators associations, consist of acquiring, assembling, and compiling engineering and statistical data into report form for the oil field as a whole. The work of each committee is carried on under the direction of some one usually designated as chairman, but the organization and plan of operation of the various committees differ in three general respects:

1. The operators of a field secure the services of an engineer who is designated as chairman or field engineer. In this capacity, he collaborates with the company engineers in acquiring engineering data for the field as a unit. The chairman's salary and expense incident to doing part of the engineering work and preparing reports are prorated on an equitable basis among the participating members. The Yates Pool Engineering Committee operates under this plan of organization.

2. The company engineers of a field organize themselves into an engineering committee and designate one of their members as chairman. None of these engineers receive special compensation, but the expense incident to preparing reports for the field as a unit is prorated among the sponsors of the committee. The Judkins Pool Engineering Committee operates under this plan of organization.

3. The operators of a field organize themselves into an engineering committee composed of an operators' committee, a full time paid chairman, a treasurer-secretary and an advisory committee. The chairman's dutics consist of organizing, supervising, managing, and maintaining a competent staff, facilities, and equipment required to carry on the program of the operators' committee. The salaries of committee employees, cost of equipment, and other expense incident to the committee's work is prorated among the participating members in proportion to their respective pipe line runs. The North Basin Pools Engineering Committee operates under this plan of organization.

The first engineering committee was a product of necessity. Like many other innovations in the oil industry, it was a necessary adjunct to proration. The Yates field was the first field in Texas to introduce voluntary proration. To carry on this work, it became apparent that there should be some agency responsible for acquiring, assembling, compiling, and correlating the engineering and statistical data for the field as a unit upon which to base agreements among the operators. The Yates Pool Engineering Committee was organized in 1928 for that purpose. It was the first engineering committee organized in the state of Texas, and perhaps the first in the nation.

The engineering data acquired by the Yates Pool Engineering Committee has been made available to the railroad commission of Texas prior to and after the adoption of the first valid proration order in Texas. In my opinion, this oil regulatory body has used this data extremely well in regulating the withdrawals from the Yates field reservoir. Data from this source shows conclusively that the field is of the combination type, i.e., both the expanding force of the gas cap and the force of water drive are active agents present for displacing oil from the reservoir to the bore of the wells.

The Yates field has been produced, however, by employing the more efficient of these displacing agents, namely, the force of water drive, which in reality is natural water flooding as distinguished from artificial water flooding. For the 8 years preceding January 1, 1943, the average reservoir pressure declined only 8.1 lb. per sq. in. while producing 71,544,489 bbl. of oil, or a decline of only 0.113 lb. per 1,000,000 bbl. produced. The field was 17 years old October 29, 1943, at which time 91 per cent of the 562 wells producing from the main limestone reservoir were still flowing.

The Yates Pool Engineering Committee through this long period of years has furnished the operators with comprehensive reports on the field each year. These reports contain such engineering and statistical data as the production of oil, water, and gas; reservoir pressure distribution; contraction and expansion of gas cap areas; reservoir displacement, and recommendations for prevention of physical waste by various corrective workover operations.

The history of cooperative oil field engineering would not be complete unless it touched upon some of the early trials of proration in the East Texas field. Some solution had to be worked out to keep the oil in the ground that was not currently needed. In order to prevent the tremendous waste, which was a grave potentiality, the final solution was that both surface and underground waste were greatly minimized by sound engineering principles.

*Paper presented at winter quarterly meeting of Interstate Oil Compact Commission, Wichita, Kansas, December 10, 1943.

Proration troubles in 1930, the year the East Texas field was discovered, became insignificant when compared with those of 1931 and 1932. The Railroad Commission of Texas held many heated hearings and received much testimony. During these years a multitude of theories were advanced to explain the mechanism of reservoir changes due to withdrawals from the Woodbine producing formation containing oil, gas, and water. At that time the knowledge of the factors and the physical laws governing the production of oil were comparatively new. Many good ideas were in the experimental stages but both the public and the courts were reluctant to put them into effect.

Fortunately, during the early years in the history of the East Texas field, a mass of reliable data was obtained for the field as a whole by the cooperativte work of a number of company engineers. In July, 1931, these engineers[1] started taking bottom hole pressure determinations at regular intervals on a selected group of key wells. Soon thereafter B. E. Lindsley[2] and other engineers with the Bureau of Mines, and a group of company engineers, with the aid of a bottom hole sampler, started a study of the physical characteristics of the oil and gas solution as it actually existed in the reservoir. From the results of these and other studies, the principles of water drive, or natural water flooding, were definitely proved for the East Texas field. From these early efforts, the value of cooperative oil field engineering became apparent and resulted in the organization of the East Texas Engineering Association in 1933.

The oil industry and the nation should be profoundly grateful to this group of East Texas engineers who pointed the way to real conservation through their cooperative efforts. They furnished sound engineering principles upon which the Railroad Commission of Texas could and did predicate orders to prevent both surface and underground waste on a scale the world has never known. Students of reservoir behavior estimate that where water drive is effective, the ultimate production will be more than 25 per cent greater if water, rather than gas, displaces the oil from the reservoir.

Since June 10, 1933, which was shortly after the courts upheld the first valid proration order in Texas, the Railroad Commission of Texas also has had its own engineers make monthly bottom hole pressure determinations on a selected group of key wells in the East Texas field. From this bottom hole pressure data, the rate of production has been set month by month so as to permit an influx of Woodbine water into the oil reservoir in an amount to almost equal the space voided by oil, gas, and water withdrawals. In this manner the reservoir pressure has been controlled by natural water flooding. More recently the reservoir pressure decline has been further arrested by the injection back into the reservoir of Woodbine water produced incident to oil production. For the 10-year period from June 10, 1933, to June 10, 1943, the pressure decline in the East Texas field reservoir has been from 1240.00 to 1016.21 lb. per sq. in. During this period the production totaled 1,496,-895,048 bbl. with a pressure drop of only 0.15 lb. per sq. in. per 1,000,000 bbls. produced. The cumulative oil production as of November 1, 1943, was 1,804,206,390 bbl. on which date there were 25,152 wells, 68 per cent of which were flowing.

The Conroe field located in Montgomery County, Texas, was discovered December 13, 1931. After 11 years of productive history, it stands out preeminently as a model of achievement in cooperative oil and gas conservation work. Pursuant to engineering testimony, the Railroad Commission of Texas adopted a spacing program of one well to 20 acres, September 19, 1932. Wide spacing alone could not achieve the conservation record established at Conroe, but it helped. This record has been made possible by both the proper spacing pattern and the adoption of operating procedures best suited to the operation of the field as a whole. These procedures were worked out by the Conroe Operators Association, a cooperative organization that came into existence early in 1932. Its members are now composed of all major companies, 90 per cent of the independents and some of the royalty owners. While most of the field work is done by company engineers, the association hires a full time resident engineer who assembles and compiles the engineering data for the field as a unit; afterward the data goes to the operators.

The Conroe field has two producing oil sands. The Cockfield sand is from 10 to 15 ft. in thickness and the underlying Conroe sand averages around 60 ft. in thickness. The combined proved area for both sands approximates 18,000 acres. Both sands have well developed gas caps. Careful completion practices, corrective operations, the choking of wells to protect the gas caps, and the proper field withdrawal rates to make effective use of natural water drive, have all contributed to the conservation of reservoir energy. After almost 11 years, the operating gas-oil ratios were but little in excess of the dissolved gas-oil ratios and 95 per cent of the wells producing from the Conroe sand were still flowing. This record of conservation is made more noteworthy by the fact that Conroe is the largest of all Gulf Coast fields and ranks high in the nation. After producing 156,000,000 bbl. of oil to October 1, 1943, the estimated remaining reserves approximated 500,000,000 bbl.

With reference to the Permian Basin area, four engineering committees are operative in West Texas and one in Southeastern New Mexico. These are:

1—Yates Pool Engineering Committee—West Texas.

2—Judkins Pool Engineering Committee—West Texas.

3—Goldsmith Pool Engineering Committee—West Texas.

4—North Basin Pools Engineering Committee—West Texas.

5—Lea County Operators Committee—Southeastern New Mexico.

In recent months the Permian Basin of West Texas and southeastern New Mexico has been in the national spotlight for two reasons, first, for the availability of crude oil for the war effort, and second, as a prospective area for new reserves. It may be of interest to compare the wells and acreage of these fields in which engineering committees operate, to the wells and acreage of the Permian Basin as a whole. The available figures for making the comparison were taken from the AIMME and are as of January 1, 1943, as follows:

Permian basin	Wells			Per cent	Proven acreage	Per cent
	Flow	Pump	Total			
Total	10,779	9,067	19,846	100.00	648,883	100.00
Committee:						
Lea County	2,835	926	3,761	18.95	160,570	24.74
Yates	515	40	555	2.80	20,000	3.08
Judkins	81	92	173	0.87	6,200	0.96
Goldsmith	914	58	972	4.90	20,000	3.08
North Basin Pools	2,769	158	2,927	14.75	129,260	19.92
Total	7,114	1,274	8,388	42.27	336,030	51.78

The Lea County Operators Committee of New Mexico (orginally Hobbs Pool Proration Committee) was organized in June, 1930, when voluntary proration was desired in the Hobbs field to assure pipe line outlets to all leases on an equitable basis. To carry on this work an engineers' advisory committee was formed and a proration umpire appointed. After the New Mexico Oil and Gas Conservation Commission was

[1]C. E. Reistle, Jr., "Effect of Different Production Rates on Pressure Distribution in East Texas," 15th annual meeting, A.P.I., Dallas, Texas, November 15, 1934.

[2]B. E. Lindsley, "A Study of Bottom Hole Samples of East Texas Crude Oil." Bureau of Mines Report Investigation 3212 (1933).

created in 1935, the state deputized the former umpire to continue his proration work and the Hobbs Pool Engineering Committee changed its name to Lea County Engineering Committee. The proration umpire was appointed chairman of this engineering committee. The engineering work of the committee is now confined principally to the 29 fields in Lea County, but in addition, it handles proration matters under the direction of the Conservation Commission, for fields in southeastern New Mexico.

The engineering committee of the Lea County Operators Committee supplies reports to the operators and state and federal regulatory bodies as follows: Proration schedule covering each field by wells and by companies; mid-month proration schedule showing new completions; monthly engineers report covering total gas, total oil, total water, whether pumping, flowing or gas lift, dry gas, summary of work being carried on by various field engineers' committees, gas-oil ratio surveys, and bottom hole pressure surveys for field by wells, and companies; annual reports for Lea and Eddy counties showing total production by wells, by companies, by fields of oil, gas, water, drop in pressure per barrels of oil produced, and increase or decrease in gas-oil ratio; monthly and yearly gasoline plant reports showing total gas processed and G.P.M. The committee has 10 employees.

The Judkins pool (Penwell) has a cooperative engineering committee composed of company engineers, one of whom serves as chairman. These engineers take periodic bottom hole pressures, assemble gas-oil ratio and water data, and have made a study of water encroachment. While this information is acquired by only a few company engineers, all of the operators contribute production and other statistical data relative to their leases, and in return are furnished the committee's reports that are quite complete. The field has a proved area of approximately 6200 acres in which 24 operators own 173 oil wells.

The Goldsmith Pool Engineering Committee started its cooperative work in March, 1937, when there was but a small number of wells in the Goldsmith field. The field now contains 983 wells owned by 26 separate operators. The proved acreage totals around 20,000 acres. The committee has maintained a very complete engineering and statistical record of the field throughout its history. As this committee was used largely as a pattern for organizing the North Basin Pools Engineering Committee, and since their methods for acquiring data are similar, a discussion of its activities will be omitted.

North Basin Pools Engineering Committee. The North Basin Pools Engineering Committee started its cooperative engineering work March 1, 1939. At that time there were a total of 281 wells in the fields in which it operates. These fields are commonly referred to as the North Basin pools from which the Committee took its name. As of January 1, 1940, or 10 months after the Committee started its work, these fields contained 701 wells. During this period, the number of participating operators increased from 32 to 45.

The committee is now composed of 78 participating members, 12 of whom may be classed as major companies and 66 as independent concerns. Three operators are not members. The committee is operative in 6 oil fields located in 5 West Texas counties. As of November 1, 1943, these fields had 3218 producing oil wells with an aggregate of around 140,000 proved acres of oil land. The estimated reserves underlying this acreage approximates one billion barrels of oil, or about 5 per cent of the nation's total. The following tabulation shows the approximate size of the North Basin pools:

Field	County	No. of operators	Number wells	Average depth	Approximate acreage
Seminole	Gaines	13	300	5286	13,500
Wasson (5100 ft.)	Gaines, Yoakum	54	1446	5158	55,000
Wasson (6200 ft.)	Yoakum	1	1	6881	250
Wasson (7200 ft.)	Yoakum	1	1	7433	250
Waples-Platter	Yoakum	3	7	5296	1,000
Ownby	Yoakum	4	8	5335	1,000
Dean	Cochran	3	8	5044	2,000
Slaughter	Cochran, Hockley, Terry	46	1447	5014	67,000
	Total		3218		140,000

The committee maintains its main headquarters office at Midland, Texas. It also maintains two branch offices, one at Denver City in the Wasson field and one at Sundown in the Slaughter field. The chief duties of the committee's engineers have been—witnessing potential tests, making bottom hole pressure surveys, spot checking gas-oil ratios and preparing monthly and annual reports for the 78 operators on the committee.

Potential tests. With the exception of the Waples-Platter field, which is on a per well basis, and the Dean field, which is on a per well plus acreage basis, potential is an important factor in the allocation formulas for the North Basin pools. In the Seminole and Ownby fields 25 per cent of the field outlet is assigned to potential and 75 per cent to acreage. In the Wasson and Slaughter fields the field outlet is allocated on the basis of 50 per cent to potential and 50 per cent to acreage.

Because of the weight given to potential in the allocation formulas, a very close check has been maintained by having committee witnesses on all wells while they are being potentialed. During the early history of the committee the Seminole, Wasson, and Slaughter fields were retested pursuant to Railroad Commission orders under the direction of a commission engineer. All retests were witnessed by both representatives of the committee and offset operators.

During and since these field retests, with the approval of the operators, the committee engineers have taken hourly gauges during potential tests for the 6-hr. flows from which the 24-hr. potentials are calculated. The vigilance exercised in witnessing potentials has resulted not only in uniformity of taking potentials as prescribed by the applicable field rules but, in addition, has resulted in a great deal of flow and gas-oil ratio data for the subject fields.

Upward of 24,000,000 gal. of acid have been used in the North Basin pools to increase the permeability in the dolomitic reservoir rock around the bore of the wells. The large acid treatments frequently result in considerable quantities of acid sludge and water left in the producing formation when new well potentials are first taken. As this sludge and water is removed by producing a well over a period of time, its productive capacity commonly increases. This condition has resulted in large numbers of retests, which, in the absence of a Railroad Commission representative, are witnessed by a committee engineer and one or more offset operators. The field rules provide that any operator in a field is given the privilege to witness any potential whether he is an offset operator or not.

Bottom hole pressures. When the committee first started its bottom hole pressure work it was possible to run two general surveys each year with only one unit. As the number of wells increased it was necessary to acquire a second unit and put the field surveys on an annual basis. Recently a third unit was added. While the commission's field rules required only one survey each year in the Wasson and Slaughter fields, it was the practice to make two general surveys per year until about two years ago. This departure from a semi-annual to an annual basis was occasioned by a shortage in skilled labor.

Bottom hole pressures have never been required in the other North Basin pools by commission orders. All fields have been accorded the same treatment as in the Wasson and Slaughter fields. The annual bottom hole pressure periods for the North Basin pools have been alternated to avoid conflicts in field surveys during the year. This arrangement

permits continuous employment for both engineering personnel and equipment, which is necessary in order to cover the large number of wells with a shortage of engineers.

Committee engineers run all the bottom hole pressures in the North Basin pools except for one company. Engineers for this company calibrate their bombs on the committee's dead weight tester and cooperate to the extent that their testing in a field is carried on concurrently with the committee. Thus, the pressures from the two sources are comparable as to time.

The bottom hole pressure work in the North Basin pools started long before there were enough wells to delineate the pressure pattern or denote the trends in field decline. For the past two years, however, development in the Seminole, Wasson, and Slaughter fields has been complete enough to give basic pressure control for future comparisons. The per acre withdrawal in these fields to date ranges from around 500 bbl. per acre to 900 bbl. per acre. Five general bottom hole pressures have been made in the Seminole field, 8 in the Wasson field and 5 in the Slaughter field. Upward of 11,000 pressure determinations have been made in these three fields.

Gas-oil ratios. The Railroad Commission of Texas requires that a gas-oil ratio test be made on each well while an official potential test is being made, provided, of course, the gas volume is sufficient to be measured by ordinary field methods. Gas-oil ratios so determined are called "potential gas-oil ratios." Since committee representatives witness all potentials, with few exceptions, a good idea of the gas-oil ratio situation in each field has been obtained from this source. Where the well makes more gas per barrel of oil than the permissible limit, as set out in the field rules, the well's allowable is penalized. This generally results in the well being worked over and the gas factor reduced before the well is re-potentialed.

For a number of years the Railroad Commission required semi-annual gas-oil ratio surveys in the North Basin pools and other fields in West Texas. About a year ago, due to a shortage in manpower and automotive equipment, the commission amended its order by requiring only one survey per year. The gas-oil ratio tests made during these general surveys are determined for each well during the time that each such well produces a quantity of oil that approximates its daily allowable production under normal operating conditions. These gas-oil ratios, designated as "operating gas-oil ratios," distinguish them from potential gas-oil ratios. Each operator reports the results of these general surveys to the commission on Form GO-2.

Soon after the operators file their gas-oil ratio reports for general surveys, the committee engineers assemble this data and compile it by leases and by fields. When this is done, the data is broken down and summarized for each field as a whole. Aside from showing the total oil and gas produced during each survey from which the weighted average gas-oil ratios are calculated, these summaries also show the general water situation in each field. The overall gas-oil ratio and water situation is of special importance to each individual operator.

High gas-oil ratios have not been a general serious problem in the North Basin pools, but will likely become more and more troublesome as the fields become older. Only recently the committee started a program of spot checking gas-oil ratios. The program was started on account of increases in ratios due to individual well depletions as well as to increases in allowable.

Committee reports. The North Basin Pools Engineering Committee's plan of operation provides that the participating operators shall be furnished both monthly and annual reports. While the committee is composed of only 78 members, a large number own properties in two or more of the subject fields. The current mailing list totals around 190 names. Representatives of the Railroad Commission of Texas and the Petroleum Administration for War are included in this number. There is no specified number of reports to be furnished any member, large or small. The usual practice has been to furnish each member as many reports as he needs, one for the main office, one or more for the branch offices, and not unusual, one for the banker.

Since and including April, 1939, all committee members have been furnished monthly reports. For the first nine months all non-members were also supplied monthly reports in order to acquaint them with the character of the committee's cooperative work. Except for the initial organization of the committee no special effort has been made to acquire new members as membership is on a purely voluntary cooperative basis. All non-members are invited to participate in discussions at all general or special meetings of the members.

Committee engineers have prepared four annual reports covering the North Basin pools. Each of the 1940, 1941, and 1942 reports contained essentially all statistical and engineering data for the entire fields at the time they were prepared. Thus each time a new annual report was prepared, the previous one could be discarded. However, when the 1942 annual reports were prepared, they were prepared with the idea of their being supplemented each year until the fields approach full development. Then it is planned to prepare a general basic report for each field. In line with that idea, the 1943 annual reports merely supplemented the 1942 reports.

The data for the monthly and annual reports is acquired from three sources—first, from the committee's field engineers; second, from the records of the Railroad Commission, and third, from the files of the operators. The data from these sources is assembled, compiled, and summarized in such a manner that it may be easily translated into meaning for either the individual lease or the field as a whole. As an aid to this end, a member of maps, charts, and cross-sections have been employed. The reports are quite complete with reference to bottom hole pressures, gas-oil ratios, oil and gas production, the water situation, potentials, well log data, and other general statistics.

Per barrel cost. The committee's paid personnel consists of a chairman and secretary with headquarters at Midland and five petroleum engineers and a trainee whose headquarters are at Denver City in the Wasson field and Sundown in the Slaughter field. Aside from these regular employees, swampers for the bottom hole pressure units are picked up in the fields. The automotive equipment consists of three pick-ups used as bottom hole pressure units and three coupes used as field cars. The committee owns and maintains field offices in both Denver City and Sundown. The salaries and other expense incident to carrying on the committee cooperative engineering work have been derived on a pro rata basis from assessments on pipe line runs as follows:

Average cost per barrel	
10 Months Period, 1939	$0.00496
12 Months Period, 1940	0.00229
12 Months Period, 1941	0.00228
12 Months Period, 1942	0.00203
11 Months Period, 1943	0.00196
Weighted average cost per barrel	$0.00231

Conclusions. The first cooperative engineering committees or associations were organized to assist in voluntary proration work. In order to have some basis for agreements, it was necessary to set up an organization to assemble and compile all available data for the field as a unit. At first this work was purely statistical. Later these organizations started acquiring engineering data on their own initiative.

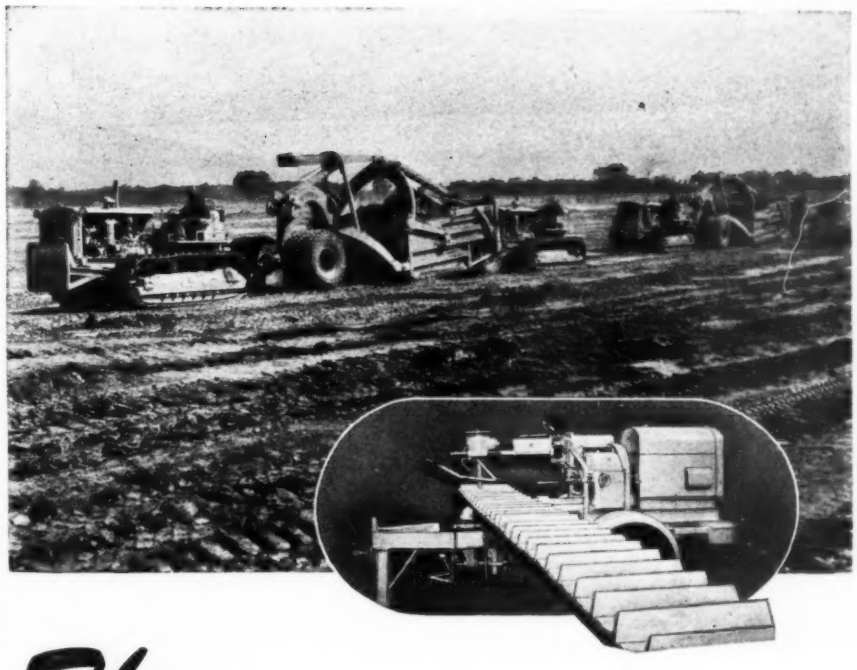
Pursuant to applicable laws after proration became a function of the state, the oil regulatory authorities made certain requirements in the interest of conservation on the producer. Foremost among these requirements were periodic gas-oil ratio and bottom hole pressure surveys. As a result of these regulations the older committees were maintained

and new committees were formed to acquire this and other new data required by the state.

One of the most important functions of a cooperative engineering committee is the compilation of all general engineering and statistical data for the field as a unit. Through monthly and annual reports the operator may see the relationship of his lease to all other leases in the field. After all is said and done, good conservation practices in the production of oil are based chiefly on two things—first, the proper completion of wells; second, the efficient rate of withdrawals from the individual well and from the reservoir as a unit. In order to accomplish this objective in a field where there is a large diversified leasehold ownership, each operator should see the picture as a whole. This data is especially desirable when going before the oil regulatory authorities for changes in allowables and corrective measures designed to prevent physical waste.

In those fields in which cooperative engineering committees are employed, the more technical engineering projects are carried on by the individual operator. Such projects as bottom hole sampling, core analyses, productivity indexes, permeability and saturation tests, and many others, could be carried on under the auspices of committee engineers. At present, however, the more highly technical projects are left to the initiative of the individual operator. Many of the major companies have their own laboratories and technical staffs for carrying on this specialized type of engineering. This same service is also available to independent operators through consulting engineering firms. In fact, many of the major companies draw heavily on this specialized service.

There are a number of fields in Texas in which the leasehold interests are small, and the company engineers as individuals exchange data with one another, much in the way that oil scouts exchange information. In a number of these fields the picture as a whole is practically as complete as in those fields in which engineering committees operate. However, where the leasehold interests are large, this simple arrangement for acquiring engineering and other data for the field as a unit does not work. Should a large number of the producers in a field undertake to carry on the more common types of petroleum engineering work individually, there would be a duplication of specialized manpower, engineering, and automotive equipment for acquiring the information. The data so acquired would still have to be assembled and compiled before it could be translated into its fullest meaning for the individual lease or the field as a whole, to say nothing of the added cost. ——— ☆ ☆ ☆



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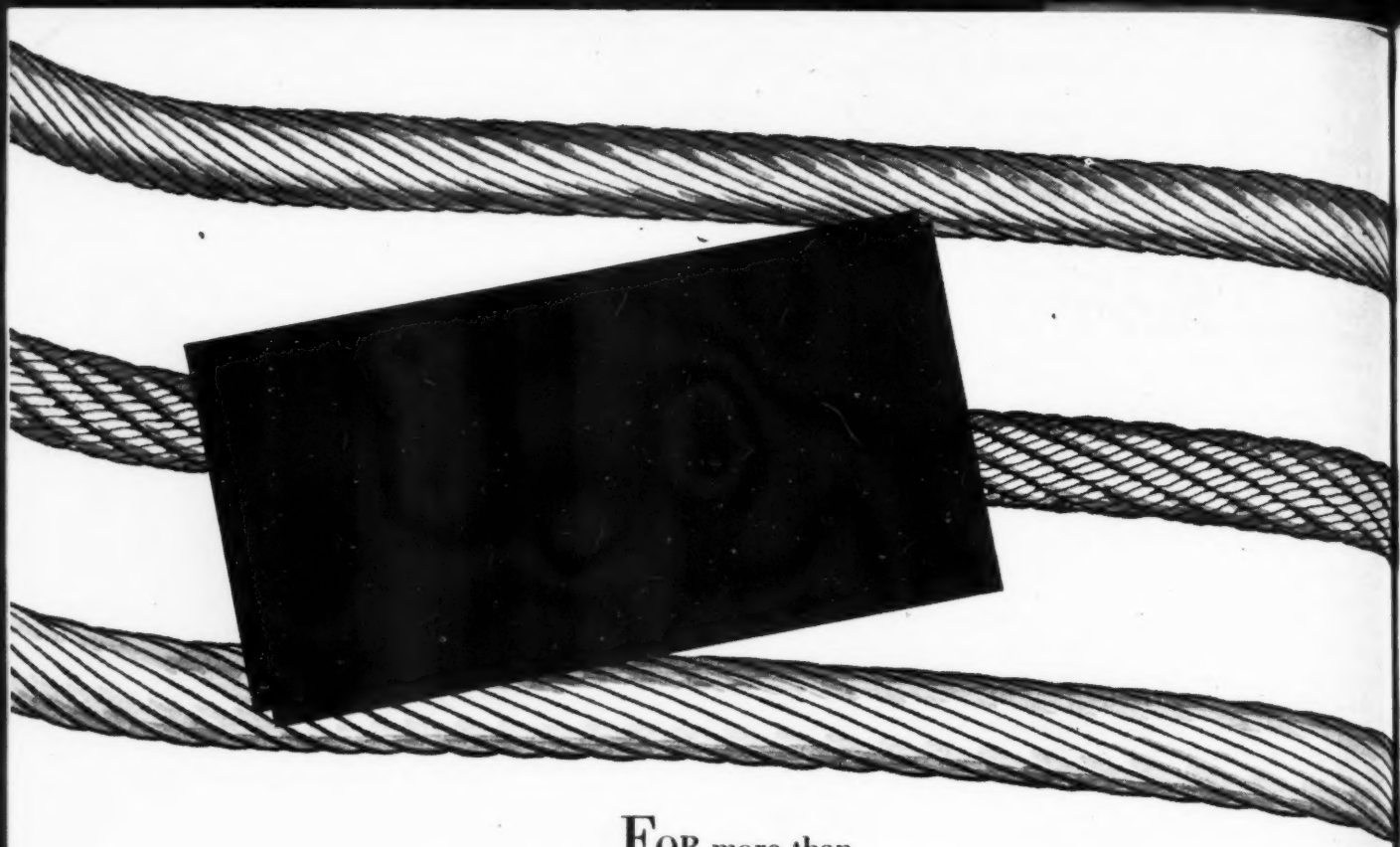

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P 306.213.

A Review of Porosity and Methods for Its Determination*

By PAUL M. PHILLIPPI
Forest Oil Corporation

HISTORY. Porosity in itself is probably the best known physical property of an oil bearing reservoir. Today, its importance in valuation, calculation of reserves, and in the efficient operation of flush production is well known. In all secondary recovery work it is necessary to know the average porosity of the oil sand before an estimate can be made of the size, type, and amount of equipment necessary for installation. Likewise, all recovery computations are based on the actual volumes of fluid present in the sand, and, in order to arrive at these values, porosity tests must be made. Porosity is also a major consideration when a barren or depleted sand is investigated for gas storage purposes. And yet it has only been within the past 25 years that the petroleum industry has recognized the term, worked out suitable techniques for testing, and applied this knowledge directly to reservoir performance.

One of the earliest reports on the porosity of an oil sand was cited by J. F. Carll in a publication of the Second Pennsylvania Geological Survey in 1880. Carll made, "in a crude way," experiments on a number of pieces of the "Third Sandstone" taken from oil wells at Tidioute, Pennsylvania. His conclusion was that the "Third Sandstone" was capable of holding from 7 to 10 per cent of its own volume of oil. These experiments were made on specimens of rock, the pores of which were more or less clogged with residuum from oil that had been held in it, and without the specimens being charged under pressure.

Bradford producers in the early days of water-flooding realized that only by a thorough knowledge of the sand characteristics would they be able to operate efficiently. To obtain this information it was necessary to core certain designated wells and subject these cores to analyses. Aside from a detailed log of the producing horizons the only other information available from the early cores was a knowledge of the porosity. Methods for determining fluid content were to come later as well as the measurement of permeability. As we glance backward today some may be inclined to regard the early attempts at core analysis as elementary according to present day standards. But rough as they might appear they were significant in arousing interest, awakening the desire and need for more information and paving the way for applied and diligent reservoir study. Laboratory techniques have steadily improved, new methods have been and are in the process of being developed to aid in the proper analysis and interpretation of oil bearing reservoirs.

The man to whom credit should be rightfully given and who pioneered in the early porosity studies of oil bearing sands was the late Dr. A. F. Melcher of the U. S. Geological Survey. He devised a method for determining accurately the porosity of sandstones and applied the method in determining the porosities of hundreds of samples of productive oil and gas sands obtained in the drilling of wells in Oklahoma, Texas, Louisiana, Wyoming, and Pennsylvania. His first progress report "Determination of Pore Space of Oil and Gas Sands" appeared in the American Institute of Mining and Metallurgical Engineers, Bulletin No. 160, published in 1920. Prior to this date considerable work had been done on the porosity of building stones, soils, and ceramic materials, but very little work had been published in English on the porosity of oil and gas sands.

During the spring of 1925 a diamond core of the Bradford Sand was taken from a well ½ mile west of Custer City, Pennsylvania. This core, sponsored by the Northwestern Pennsylvania Oil Producers Association by private subscription of its members, was taken for the express purpose of obtaining information in regard to the nature of the reservoir rock and was submitted to the U. S. Geological Survey for study. Dr. Melcher published the results of porosity determination on this Custer City core and at the same time laid the basic foundation from which present day core analysis has been developed.

Definition. Porosity is defined as the fraction of the space in a unit volume of substance that is not filled by solid material. In oil reservoirs the porosity represents the percentage of void space that is available for occupancy by either liquids or gases. It determines the storage capacity of the sand and is generally expressed in percentage terms. For example, in 100 cu. ft. of sandstone of 15 per cent porosity, there would be 15 cu. ft. of pore space. This simple explanation is fairly easy to visualize but in an oil sand the 15 cu. ft. of pore space, or void volume, would actually be composed of many miles of intricate microscopic channels, which we call pores. The average channel diameter of the Bradford sand has been reported by Krynine as approximating one-third thousandth of an inch. Porosity tests report as percentage the aggregate per cent of voids per unit volume.

Theoretically, spheres ⅛ in. in diameter will have the same per cent of porosity as spheres ½ in. in diameter if the geometric arrangement of the spheres is the same in both cases. But sand grains are not true spheres in shape. They are more often angular in widely distributed shapes and sizes. We therefore see that the porosity is affected by the arrangement, shape, and uniformity of the sand grains, the extent to which the rock has been compressed, and by the kind and amount of cementing material.

Naturally a great number of these interstitial channels are not connected with each other, being completely isolated so that a certain discontinuity results. During sedimentation, small grains may have sifted in between the larger grains or cementing material may have plugged off what previously were open pores. It is necessary then that a distinction be made between the two types of porosity which are known as *total* and *effective* porosity.

Total, sometimes referred to as *absolute porosity*, includes all the voids in the sandstone or other rock. *Effective* porosity includes only those pore spaces that are interconnected and is generally less but can never be greater than the total porosity. Methods for determining both will be discussed later although most present day tests measure only the effective porosity. The obvious reason for this is that only the connected pore spaces contain the oil available under present methods of productiton.

Preparation of samples. We now come to the various methods used for the actual porosity determination. Although there are numerous devices and procedures for achieving the final result there is a certain amount of necessary preliminary work that has been fairly well standardized.

The samples are first cut down to a convenient size for testing, depending, of course, upon the method involved. The size and shape of the sample is of no great importance as the result of the test is reported in percentage. However, most laboratories prefer a fairly large sample approximating 5 to 6 ml. bulk volume. Each sample is given an identifying mark or symbol and then placed in an extractor to remove any oil film, paraffin, and residuum that remain in the sand. For solvents, ether, butanol, or carbon disulphide are pre-

*Presented at the mid-year meeting of the board of directors of the Independent Petroleum Association of America, Bradford, Pennsylvania, April 28, 1944.

ferable, each of which has its advantages, but because these are highly inflammable many laboratories employ carbon tetrachloride as the cleansing solvent. The time of extraction depends upon the condition and size of the sample, and the rate of heating. Small extractors of the Soxhlet type perform the job more quickly than larger extractors of the same design, as the rate of extraction is faster. A good rule is to extract until the solvent in contact with the samples remains water white and is not discolored. With large extractors 24 hr. of continuous running is usually required. When time does not allow prolonged extracting the operation can be hastened by the use of pressure extractors, which, as indicated by their name, utilize pressure for forcing the solvent through the sample until it is thoroughly cleansed.

After extraction, the samples are placed in an electric oven and allowed to heat uniformly for several hours at a temperature of 215° F., until any free water or solvent remaining in the sand is removed at this temperature. Higher temperatures are to be avoided as dehydration of one or more of the constituent minerals might occur, resulting in a higher porosity than actually exists.

After drying, the samples are carefully brushed and examined for cracks or minute crevices. Any small projections or loose grains that might later break away from the specimen should be removed, and it is well to keep the samples in a desiccator.

Porosity formula. The general formula for percentage of porosity by volume determinations is

$$\text{Per cent porosity} = \frac{\text{pore volume}}{\text{bulk volume}} \times 100$$

This equation shows us that in order to arrive at the percentage porosity of a sample means must first be found for quantitatively determining (1) the volume of the pore spaces or pore volume and (2) the bulk volume of the sample being tested.

Numerous methods have been developed for determining each of these requisites and there is not much deviation in the final results. The method to be used rests with the technician and usually depends upon what equipment is available and whether total or effective porosity is to be determined. Effective porosity is usually measured directly whereas total porosity pore volume is indirectly determined by deducting the volume of the mineral grains from the bulk volume.

It is beyond the scope of this paper to present all of the various tests in detail but an effort will be made to make brief mention and call attention to those methods which are used. First we will discuss the various procedures for determining bulk volume.

Methods for determining bulk volume. It is sometimes necessary to make bulk volume measurements before the pore volume can be ascertained. In order to maintain our proper sequence we will discuss the more common methods by which bulk volume can be determined.

1. By displacement. First, the sample is saturated with acetylene tetrachloride until it takes up no more liquid. Then the surplus fluid is carefully wiped off and the sample is placed in a graduated cylinder containing the same liquid. The fluid level having been read before the sample was added is now read again and the increase in volume is the bulk volume of the sample. Some operators prefer to use the Russell apparatus rather than an ordinary graduated cylinder but the principle of displacement is the same in both instances.

2. By pycnometer. The pycnometer method is probably the most convenient and rapid method of all. The bulk volume is determined by displacing mercury from a wide mouthed pycnometer and then measuring the volume of the mercury displaced. An electric pycno-

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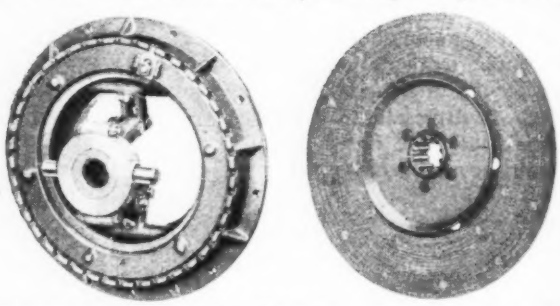

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meter method that measures mercury displacement with a micrometer and uses an electric light to indicate the mercury level in the measuring tube has been adopted by some laboratory technicians.

3. By paraffin coating. In the paraffin-coating procedure the dry sample is coated with a thin layer of molten paraffin. It is weighed first in air and then in water. The loss of weight of the sample in water compared to its weight in air is a measure of the weight and volume of the water displaced. Allowance is made for the coating material by computing its volume which is deducted from the volume of water displaced.

4. By calculations from dimensions. If the sample has been prepared in true geometrical shape and is a well cemented sandstone, the bulk volume can be calculated from the dimensions. This method is better adapted for large samples than small ones where the likelihood of error would be much greater.

Methods for determining pore Volume. 1. Washburn-Bunting method. The Washburn-Bunting method as adapted by A. C. Simmons, is a direct procedure for determining the effective pore volume of an oil or gas sand and is probably more generally used than any other method. It is used by many core testing laboratories throughout the country and is extremely fast and accurate. The operaton is based upon the expansion of air in the communicating pores of sand under high vacuum created by mercury. After the air has been expanded out of the sample it is trapped above the mercury, measured at atmospheric pressure in the graduated tube forming the upper portion of the porosimeter and the volume reported as pore space in milliliters. Due to mercury penetration samples run in this manner are unsuitable for further testing.

2. Stevens method. The Stevens method of determining the effective porosity of oil reservoir rocks is comparable to the Washburn-Bunting method, being of the gas expansion type with the added advantage that the sample does not come in contact with the mercury in the porosimeter. The sample is left in its original condition and can be used for any further test.

3. Barnes method. The Barnes procedure is gravimetric and likewise determines the effective pore volume of a rock. It is particularly adapted for small samples and requires skillful manipulation of an analytical balance. The method is based on the comparison of the dry weight of the sample with its weight when saturated with a liquid of known density. Subtracting the dry weight from the saturated weight a figure is obtained that represents the weight of the fluid filling the pore spaces. The specific gravity of the fluid known its volume may then be computed. A vacuum pump is required to thoroughly evacuate the sample prior to saturation. Acetylene tetrachloride is usually used as the saturating fluid.

4. Boyles Law method. A method developed by the U. S. Bureau of Mines, and reported in their Report of Investigations 3352 determines the volume of the mineral substance of a rock by gas displacement. An empty bomb is charged with gas to a pressure of 4 or 5 atmospheres and then discharged by releasing the gas slowly into a graduated burette where its volume is measured. The same process is repeated with a sand sample in the bomb and the difference between the two volumes is equivalent to the volume of the mineral grains. Effective pore volume is then determined as the difference between bulk volume and grain volume.

5. Kobe method. The Kobe method measures effective porosity by using hydrogen under pressure. This apparatus consists of an upper chamber for measuring the gas and a lower chamber for holding the sample to be tested. Both chambers are connected with each other. After flushing the system with hydrogen to remove all air the connecting valve is closed and the pressure in the upper chamber built up by admitting gas. The valve connecting the two chambers is then opened and the gas from the upper chamber expanded into the new volume. By measurement of pressures and proper calibration of the apparatus the volume of the sand grains and any pore space that the hydrogen does not enter may be calculated.

6. Melcher method. The Melcher method for determining total porosity is based on the principle that the volume of a fragment of sand minus the volume of its individual grains equals the volume of the pore space. All the measurements are made gravimetrically. Particular skill and a deft touch is demanded of the operator while reducing the sand clumps or clusters to individual grains. This is accomplished with a small mortar and pestle and frequent observation under a high power microscope to make certain that separation is complete. The individual grains are first weighed in a pycnometer of known volume and then the pycnometer is reweighed after being filled with a liquid of known density. The volume of the additional liquid is subtracted from the volume of the pycnometer to determine the individual grain volume. Bulk volume less the individual grain volume equals the pore volume. This method is tedious and painstaking and an error by loss is quite likely to occur during the grinding and transferring process.

7. Russell method. The Russell pro-

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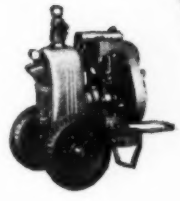

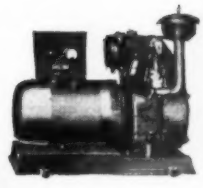

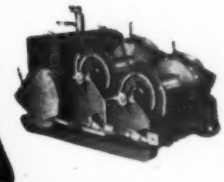

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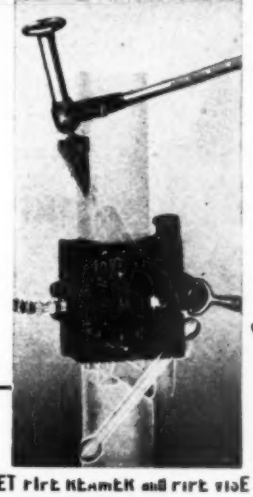

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cedure determines total porosity, and is based on the same principles as the Melcher method except that it is performed volumetrically using acetylene tetrachloride in a special type porosimeter. The sample is first immersed in acetylene tetrachloride until saturated and then placed in the Russell porosimeter and bulk volume determined. Afterwards, it is reduced to grain size and the mineral substance volume determined in the same manner. The difference between the two results is the total pore volume. This method is subject to error in manipulation.

8. Density method. The density method assumes that the specific gravity of the mineral constituents is constant, and therefore is not as exact as the others. It may be used for approximate calculations of total porosity. The sample is weighed dry and this result devided by the specific gravity (2.65 for quartz) yields the volume of the mineral substance. This figure deducted from the total bulk volume is the pore volume of the sample.

After both the bulk volume and pore volume of a sample have been determined it is simple arithmetic from there on to place these values in their respective places and calculate the percentage porosity from the given formula.

Conclusion. In 1940 the American Petroleum Institute Sub-Committee on Core Analysis and Electric Logging conducted an investigation of the comparativeness of results obtained by core analysis laboratories under routine conditions. Standard samples were sent to different laboratories for porosity testing by the various methods which have been described. Their report stated "that the results obtained from the many types of apparatus were in quite good agreement. The data lead to the conclusion that all of the types of porosity apparatus upon which standard samples were run, gave comparative and satisfactory information."

Regardless of the method employed, the necessary equipment for the determination of porosity is inexpensive. The actual preparation, testing, and calculation of porosty is routine work and can be quickly learned by an inexperienced operator. However, the application of these data and the interpretation of results demand the skilled services of a technician well versed in reservoir performance.

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Positive Colloid Muds for Drilling Through Heaving Shale*

By DONALD C. BOND
The Pure Oil Company

THE nature of heaving shale. The penetration of heaving shale formations during drilling may be inferred from several effects that can be noted at the surface. The mud pumps may slow down or the circulation of mud may cease entirely.[1] The physical properties of the drilling mud, such as specific gravity, viscosity, or gel strength, may change rapidly.[2] (These effects are not to be confused with those caused by mixing of the mud with brine or with cement.) Cavings of shale may appear in the mud returns.[3] Finally, the drill pipe may be seized so firmly that it cannot be turned.[4]

It is found that these effects are symptoms of two conditions that may exist in the hole. In some instances, a large cavity filled with sticky, viscous shale is formed at the bottom of the hole when the heaving shale is penetrated by the drill.[5-8] In other cases a plastic mass of swollen shale sloughs into the drill hole at some point above the drill. In either case the result is a decrease or complete cessation of circulation of mud, accompanied by increased resistance to the rotation of the drill pipe.

It is generally accepted that heaving shale contains large amounts of bentonite, which is a hydrophilic colloid that hydrates and swells very much when in contact with water.[9,10] When heaving shale is penetrated during drilling, the bentonite in the shale absorbs water from the drilling mud, thus causing the shale to swell and fill the space between the drill pipe and the wall of the drill hole. This process may continue until the circulation of mud is stopped and the drill pipe is firmly held by the mass of plastic shale.

Various other theories have been advanced concerning the nature of heaving shale. It has been postulated that the natural, unhydrated shale has plastic properties, which allow it to flow into the drill hole under the pressure of the overburden.[11] Some investigators believe that the heaving of shale is caused by the presence of pockets of high-pressure gas sealed in the relatively impervious shale.[12] Others hold that the bearing power of the formation is decreased by tilting of the horizontal strata, causing the shale to break or chip when penetrated by the drill.[11] Various shales having these properties may or may not exist; however, here we shall apply the term "heaving shale" only to bentonitic shale capable of plasticizing when placed in contact with water.

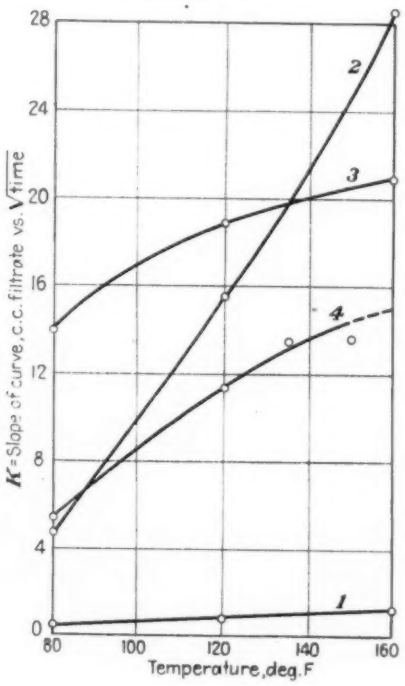
Properties of clays and shales. Clays are the final products in the alteration of igneous and metamorphosed aluminosilicates by weathering processes, which include hydration, devitrification, and leaching of alkalies and other bases. Under the influence of high temperatures and pressures, sedimented clays are successively transformed into shale, slate, mica schist, and mica.[13]

A suspension of clay in water is a typical colloidal system whose properties depend to a large degree on the fact that the suspended particles all carry electrical charges of the same sign; ordinary clay particles carry negative charges. When two clay particles, each negatively charged, approach one another, the electrical forces of repulsion hinder the coalescing of the particles. Large agglomerates of the colloidal material cannot collect, therefore, and the result is a more or less stable suspension.

A colloidal clay particle bearing negative charges is always surrounded by positive ions, the sum of whose charges is equal to the total negative charge on the particle. These positive ions generally may be replaced by other positive ions, so they are called the "replaceable base" of the clay.

Fig. 1. Filtration characteristics of various muds at different temperatures.

1. Positive colloid mud (No. 3 in Table 4). 2. Silicate mud, W. W. Smith No. 1, Brazoria County, Texas. 3. Aqueous mud; average from Clay City, Illinois. 4. Very good aqueous bentonitic mud, Gatewood Newberry No. 3.



The properties of a clay vary enormously with changes in the amount of replaceable base and the kind of replaceable base.[14,15] Natural kaolin, which has a very low base-exchange capacity, settles rapidly from suspension. On the other hand, bentonite, which has a high base-exchange capacity, forms permanent suspensions. Clays containing sodium as the replaceable base are usually highly dispersed, in suspension, and relatively impervious to water, when filtered. Calcium clays are generally porous and granular and cannot be maintained in stable suspension.

Any agent that decreases the charge or the potential of a colloidal particle is said to have a "flocculating" effect on the particle. For example, the addition of a solution of calcium chloride to a suspension of sodium clay reduces the electrical potential of the sodium clay, so the calcium chloride is said to "flocculate" the clay partially. The addition of a sufficient amount of a salt of aluminum or thorium to clay will reduce the charge on the clay colloid to zero, completely flocculating the clay. Flocculation of clay makes it unsuitable for use in drilling mud. Flocculated clay loses its plasticity; it settles from suspension much more quickly than ordinary clay, and it is more permeable to the passage of water.[16,17]

Any agent that increases the charge or the potential of the particles of a colloid is said to have a "deflocculating" effect on that colloid, because it raises the stability of the colloid. Sodium tannate and complex sodium phosphates are typical deflocculating agents for clay suspensions.

As a general rule, any electrolyte that acts as a good *deflocculating* agent for *negative* colloids will act as a *flocculating* agent for *positive* colloids, and vice versa. Large amounts of any electrolyte have a flocculating effect on both positive and negative colloids. Certain organic solvents have a similar effect on hydrophilic colloids such as clay.

Many clays swell, more or less, when they absorb water. This is especially true of bentonite containing sodium as the replaceable base, which swells in water to many times its dry volume.

The replaceable base in bentonite can be removed by a process called "dialysis." Dialyzed bentonite, containing no base, does not swell when placed in water, indicating that swelling of the clay is caused by the hydration of the exchangeable base.[18] To minimize the

*Presented before the American Institute of Mining and Metallurgical Engineers, New York City, February, 1944.

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TABLE 1

Fluids and processes for drilling through heaving shale

A. Crude oil or topped crude as drilling fluid.[5, 19, 20]
B. Oil plus an oil-bearing filter clay as drilling fluid.[21]
C. Red lead in gas oil, plus oleic acid, as drilling fluid.[22]
D. Mixture of two thirds sodium silicate and one third saturated sodium chloride as drilling fluid.[23–25]
E. Concentrated salt solutions as drilling fluids.[5, 23, 26, 27]
F. Zinc chloride or sodium nitrate as drilling fluid.[28]
G. Sugar solution as drilling fluid.[30, 48]
H. Zinc chloride-cellulose solution as drilling fluid.[29]
I. Various cements for sealing off the drill hole.[12, 31]
J. Precipitation of calcium silicate in pores of formation.[32]
K. Precipitation of silicic acid in pores of formation.[33, 34]
L. Solution of hydroxyethyl cellulose in NaOH or of cellulose acetate in acetone as drilling fluid.[35]
M. Sealing off water formations by forcing $SbCl_3$ or $SiCl^4$ into hole, to precipitate SbOCl or H_2SiO_3, respectively, when diluted with connate water.[36]
N. Emulsion of oil and water.[5, 22]
O. Methylene iodide and other dense liquid compounds as drilling fluids.[37]
P. Solution of tar in phenol as drilling fluid.
Q. Molten sulphur as drilling fluid.[38]
R. Heating mud to 100°C.[39]
S. Dynamiting of waxy shales.[40]
T. Freezing of wall of hole.[5]

swelling of bentonite, one should replace the highly hydrated sodium base with another base that is less hydrated, such as calcium, or, better, aluminum. If the negative charge on the bentonite particle were completely neutralized, the bentonite should exhibit no swelling when placed in contact with water.

Ordinary bentonite exerts a measurable osmotic pressure, while dialyzed bentonite does not. Since dialyzed bentonite does not swell, this indicates that swelling is an osmotic phenomenon, so any agent that will reduce the thermodynamic activity of water, such as salts in high concentrations, should reduce the swelling of bentonite.[10]

TABLE 2

Mechanical methods for drilling through heaving shale

A. Maintaining continuous circulation of mud by means of a special valve on each section of drill pipe.[1]
B. Cement casing to bottom of hole before heaving takes place.[1]
C. Slow drilling to build up wall of hole.[1]
D. When caving starts, stop pumps, withdraw drill to a point above the cave, then try to redrill hole, rebuilding wall hole.[1]
E. Use collapsible wire-line bit, which can be withdrawn without removing drill pipe from hole.[5, 42]
F. Use fairly large heavy drill pipe at start of shale. Continue drilling until this becomes stuck. Recover collapsible bit, cement string of pipe in hole. Then run in next smaller size of drill pipe and continue drilling until it is stuck. Repeat until hole becomes too small.[7, 42]
G. Drilling under gas pressure exerted at surface.[5, 12, 43, 44]
H. When caving ceases, dump construction cement on bottom of hole through drill pipe. After 24 hr. drill through cement. Repeat each time caving occurs.[45, 46]
I. Directional drilling to cause drill pipe to penetrate tilted shale formations perpendicularly.[45]

Methods for drilling through heaving shale. Table 1 lists a number of fluids and chemical processes that have been used or proposed for drilling through heaving shale. Some mechanical methods of combating heaving shale are given in Table 2.

Oil-base muds (Table 1, A, B, C) have been used in drilling with some degree of success. However, they are likely to cause much trouble if they become mixed with considerable amounts of brine, because the fine clay and shale cuttings taken up by the mud may form a hard, granular precipitate under these circumstances. Because of the high electrical resistivities of oil-base muds, it is very difficult to run electrical logs in holes filled with such muds.

Various salt solutions have been used as drilling fluids (Table 1, D, E, F). Here the object is to prevent the hydration of shale by lowering the activity of water and by flocculating the shale itself, as described above. In some cases,

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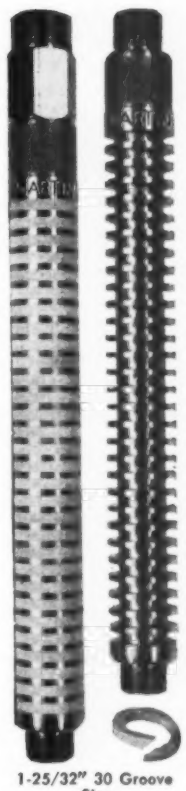

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TABLE 3

Effect on heaving shale of addition of basic dye to bentonite

Mixture No.	5 per cent bentonite suspension*, cc.	5 per cent methylene blue added, cc.	Charge on colloid†	Effect on heaving shale‡
1	20	0	Negative	Swells and disintegrates in less than 3 hr.
2	20	1	Negative	
3	20	2	Negative	
4	20	3	None detectable	
5	20	4	None detectable	Swells and disintegrates in less than 12 hr.
6	20	7	None detectable	
7	20	10	None detectable	
8	20	15	Positive	Unchanged in 5 days.
9	20	20	Positive	

*Mixtures diluted to 100 cc. with distilled water.
†Charge as determined by cataphoresis experiment.
‡Shale cuttings from W. W. Smith No. 1, Brazoria County, Texas.

as with zinc chloride solutions, the specific gravity is so high that the addition of weighting solids is not required. The major objection to this type of drilling fluid is that the fluid is so highly flocculating that it cannot retain colloidal material in stable suspension. This makes it impossible to hold drill cuttings in suspension when mud circulation is stopped. It also makes it impossible to prevent the loss of large quantities of fluid into porous formations because there is no fine colloidal material present to form an impervious filter cake on the wall of the hole.

In the sodium silicate mud this objection is partly overcome by the use of a fluid that is viscous enough to retard the settling of cuttings in the drill hole. Likewise, the high viscosity of the fluid reduces the loss of fluid into the formation drilled, even though no impermeable colloidal filter cake is formed. However, at the high temperatures existing in deep holes the viscosity of such a silicate solution is greatly reduced, causing much trouble because of the settling of cuttings and the formation of a thick filter cake.

Another serious objection to the use of a concentrated salt solution as a drilling fluid is that such a solution has a very low electrical resistivity. This causes the electrical log taken in a hole filled with such a mud to be distorted and difficult to interpret.

Various methods of sealing or cementing the wall of the drill hole have been used or proposed for penetrating heaving shale (Table 1, I to M). The most practical methods involve batch cementing, which requires much time and may be costly. In many places heaving shale layers are very thick, so that the number of batch cementing jobs required is likely to be prohibitive. Moreover, the shale is likely to heave while the hole is being drilled and before it can be sealed.

The other fluids and processes mentioned in Table 1 are open to serious objections of one kind or another. Methylene iodide *(O)* and similar heavy liquids are far too costly for consideration as drilling fluids. Molten sulphur *(Q)* has been used in drilling one shallow hole, but much trouble was encountered. Use of a refrigerated drilling fluid *(T)* has been considered but, besides being costly, such a method would be accompanied by great practical difficulties.

This discussion emphasizes the dilemma of the mud engineer who tries to prepare a drilling fluid for penetrating bentonitic shale. There are many substances which may be added to drilling mud which will decrease the swelling of shale. The difficulty is that all of the materials used or suggested for this purpose thus far are agents which have a very deleterious effect on the mud itself.

Positive colloid muds. Consideration of the properties of bentonite led us to the conclusion that a mud containing positively charged colloidal material, rather than ordinary negative clay colloids, should be satisfactory for drilling bentonitic shale. As pointed out above, substances that act as deflocculating, or dispersing, agents for positive colloids are excellent flocculating or precipitating agents for negative colloids. Bentonitic shale placed in contact with a positive colloid should be flocculated because of the neutralization of the negative charge on the bentonite by the deflocculating agent of the positive colloid. The surface bentonite should also be neutralized by the positively charged colloidal particles themselves. In either case neutralization of the charge on the bentonite would prevent the swelling of the shale. Furthermore, the pH range over which positive colloids are stable is slightly on the acid side, where the hydration and swelling of bentonite are very small. Therefore heaving shale should not swell or disintegrate when in contact with a positive colloid mud.

There are no naturally occurring positive colloids having all the properties essential in the drilling mud. Probably the nearest approach to a satisfactory positive colloid mud among commonly known colloids is represented by the class of hydrous oxides of iron, aluminum, thorium, etc., but these leave much to be desired in many respects.

It is necessary, therefore, to prepare positive colloids having suitable properties for drilling muds. It has been known for some time that positive colloids can be made by the addition of powerful deflocculating agents (for positive colloids) to suspensions of various negative colloids. For example, a suspension of negatively charged bentonite can be converted to a positive colloid by the addition of salts of thorium and other polyvalent cations, acid gelatin and other proteins, or basic dyes such as methylene blue and methyl violet. We have found that the positive colloids showing the most promise as drilling muds are those formed by the addition of solutions of basic dyes to suspensions of bentonite.[46]

The theoretical conclusions given above are borne out by actual tests. Heaving shale does not swell or disintegrate when placed in contact with a suspension of bentonite containing sufficient basic dye to render the bentonite positive. Table 3 shows the results of some typical experiments with mixtures of bentonite and basic dye in contact with heaving shale.

It is possible to prepare mixtures containing only bentonite and basic dye that are fairly satisfactory for a drilling mud, but we have found that the properties of such muds can be greatly improved by the addition of certain substances.

The dye-bentonite mixtures have a tendency to form a stable foam, which might increase the danger of gas cut-

TABLE 4

Result of tests on methyl violet bentonite muds containing wheat flour

Mud No.	Composition of mud by weight, per cent					Sp. Gr.	pH	Stability		Stormer viscosity tests			100-lb. filter test, 120°F. 16 sq. in.	
	Bentonite	Methyl violet	Wheat flour	Diglycol laurate	Baroid-O			Free liquor, cc.	Sp.gr. of top layer	Viscosity, centipoises	Initial gel strength, grams	10-min. gel strength, grams	Filtrate in 30 min., cc.	k*
1	0.67	1.33	5.00	0.1	42.8	1.5	5.8	0	1.48	155	5	60	6	0.5
2	0.67	1.33	4.00	0.1	42.8	1.5	6.4	0	1.42	89	4	50	13	0.9
3	0.67	1.33	3.33	0.1	42.8	1.5	6.2	0	1.40	57	3	45	11	0.8
4	1.33	2.00	2.67	0.1	42.8	1.5	6.0	0	1.44	55	6	60	16	1.3
5	0.67	1.33	2.67	0.1	42.8	1.5	6.4	0	1.38	46	3	30	1	0.5
6	1.00	2.00	2.67	0.1	42.8	1.5	6.2	0	1.40	46	4	30	18	1.9
7	1.00	2.00	3.33	0.1	42.8	1.5	5.9	0	1.44	71	4	40	14	1.9

No effect on heaving shale was perceptible in 3 months.

*Units of k are $\frac{\text{cc.}}{\sqrt{\text{min.}}}$ for 16-sq. in. filter.

ting during drilling. It has been found that foaming can be eliminated by the addition of a small amount of diglycol laurate or a similar compound.

Certain properties of dye-bentonite muds, such as stability, gel strength, and filtration characteristics, are greatly improved by incorporating a small amount of wheat flour or starch in the muds. The flour or starch does not undergo decomposition by organisms because of the preservative action of the dye in the mud.

Muds having high specific gravities are obtained by the addition of barites, as with ordinary muds.

Dye-bentonite muds. The results of tests on some representative methyl violet bentonite muds are given in Table 4. The methods used in making the tests were as follows:

pH.—The pH values of the muds were determined by means of a cell consisting of an antimony electrode and a calomel electrode.

Stability.—A 250-cc. sample of the mud was allowed to stand in a 250-cc. graduate for 24 hr. at 77° F. The supernatant liquor was then decanted and the specific gravity of the top 25 cc. of mud was determined.

Stormer viscosity.—The time required for 100 rotations of the cylinder was determined, using various weights on the pan of the apparatus. The weight required to give 600 r.p.m. was found by interpolation and the viscosity of the mud was read from the calibration curve of the viscosimeter.

Initial gel strength.—The weight required to start the rotation of the inner cylinder of the Stormer viscosimeter was determined immediately after the mud had been agitated by rotation of the inner cylinder. This weight was considered a measure of the initial gel strength of the mud.

10-minute Gel Strength.—The mud was agitated and then allowed to stand 10 min.; the weight required to start the rotation of the inner cylinder was then determined. This weight was taken as a measure of the thixotropic quality of the mud.

Filtration characteristics.—The muds were filtered under a pressure of 100 lb. per sq. in. through a filter area of 16 sq. in. at 120° F. and the volume of filtrate was read periodically. At the end of the test the thickness of the filter cake was measured, if possible.

When a mud is filtered in the manner described, the volume of filtrate v and the time t are related by the following equation:[47]

$$v = k\sqrt{t} + E$$

The constant k is determined by measuring the slope of the curve obtained by plotting v against $\sqrt{t}$. This constant is a measure of the ability of the mud to form an impermeable filter cake. The smaller the value of k, the lower the rate of filtration of liquid from the mud. For muds of similar composition the thickness of the filter cake decreases as k decreases. Values of k can be determined more accurately than cake thickness or filtrate volume.

Effect on heaving shale. A heaving-shale cutting (obtained while drilling with silicate mud) was carefully scraped to remove the coating of sodium silicate. The shale cutting was then placed in the mud and inspected periodically for evidence of swelling or disintegration.

After standing at high temperatures for a long period of time, these muds undergo little or no change in properties. Table 5 shows the effect of maintaining positive colloid muds at 150°F. for 4 weeks.

Corrosion tests were made on representative positive colloid muds, saturated with air, in contact with metals similar to those used in drilling. It was found that the loss in weight due to corrosion was negligible at the temperatures employed (up to 150° F.).

The behavior of the muds toward various materials encountered during drilling can be determined only by

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means of actual tests in the field. The following discussion is purely speculative, but it gives some idea of what should be expected during drilling.

Very little trouble, if any, should be caused by the infiltration of formation water into the drill hole filled with positive colloid mud. Because of the superior sealing qualities of the mud, it should be possible to use a specific gravity great enough to substantially prevent the influx of water.

The effect of mixing the mud with solid drill cuttings will depend to a great degree on the size of the cuttings. If the cuttings are very finely pulverized and disintegrated, there is a possibility of interaction between the dye (in the mud) and shale or limestone cuttings, resulting in the removal of the dye from the mud. On the other hand, if the cuttings are large fragments or slices, they should have little effect on the mud. The effects of drilling through fairly thin layers of limestone probably could be overcome by adjustment of the pH of the mud. Very thick layers of limestone might make it difficult, or impossible, to use a mud of this type. It is believed that the amount of lime ordinarily encountered in heaving shale areas is not large enough to cause serious trouble, but this point can be established only by actual drilling tests.

Positive colloid muds vs. silicate muds. Thus far the drilling fluids that have been the most nearly satisfactory for drilling through heaving shale are the silicate muds. The positive colloid muds described possess certain distinct advantages over silicate muds, which can be understood more easily if one realizes the differences in the nature of the two types of muds.

In the silicate muds the liquid suspension medium usually consists of two thirds D-brand sodium silicate, by volume, plus one third saturated sodium chloride solution. This mixture, being strongly alkaline as well as saline, has a great flocculating, or precipitating, effect on ordinary negative clay colloids, for such colloids form stable dispersions only in the pH range from about 8 to 12 and in the absence of high concentrations of electrolytes. For this reason the clay and bentonite present in silicate muds are *not* dispersed in the form of electrically charged, hydrated, colloidal particles. These particles are prevented from settling rapidly because of the high viscosity of the silicate mixture. The flocculating nature of the silicate mixture also prevents the swelling and disintegration of heaving shale. Lastly, the wall-sealing properties of the silicate muds are due to the high viscosity of the liquid silicate suspension medium, rather than the presence of highly hydrated, colloidal material with low permeability to water.[49]

TABLE 5
Effect of aging positive colloid muds 150° F.

Mud No.	Composition of mud, per cent	100-lb. filter test, 120°F., 16-sq. in. filter area, cc. filtrate in 30 min.		Stormer viscosity at 120°F., centipoises	
		Initial	After 4 weeks standing at 150°F.	Initial	After 4 weeks standing at 150°F.
1	1.33 bentonite 2.00 methyl violet 2.67 wheat flour 42.8 baroid-O 0.1 diglycol laurate	16	19	55	60
2	0.67 bentonite 1.33 methyl violet 4.00 wheat flour 42.8 baroid-O 0.1 diglycol laurate	13	8	89	81
3	1.00 bentonite 2.00 methyl violet 2.67 wheat flour 42.8 baroid-O 0.1 diglycol laurate	18	15	46	46

In contrast to silicate muds, the positive colloid muds contain highly hydrated, colloidally dispersed particles bearing positive electrical charges. When the mud is placed in contact with heaving shale, the methyl violet (or other basic dye) in the mud neutralizes the natural negative charges in the surface of the shale particles. After the shale is neutralized, it cannot swell, for the ions whose hydration is responsible for the swelling (Na, K, etc.) have been replaced by dye ions.

While the wall-sealing ability of the silicate mud depends upon the high viscosity of the liquid suspension medium, the sealing ability of the positive colloid muds is caused by the presence of colloidal material that is almost impermeable to water, even at high temperatures.

The great differences between positive colloid muds and silicate muds are demonstrated by the results of filter tests carried out on these muds at various temperatures. Fig. 1 shows the values of the filtration, or sealing, constant k for representative muds of these two types, as well as two typical aqueous muds, at various temperatures.

The very low values of k obtained for positive colloid muds show that these muds seal very rapidly and that very little liquid could be forced from such a mud into the formation being drilled. This results in a very thin filter cake, minimizing the possibility of stuck drill pipe. Furthermore, the sealing ability of the positive colloid muds undergoes only a slight change when the temperature is increased from 80° to 160° F.

On the other hand, the silicate mud loses much more filtrate than the positive colloid mud does under the same conditions, even at low temperatures. Much more serious is the fact that the silicate mud rapidly loses its ability to seal when the temperature is raised, so that in this respect it is worse than an ordinary aqueous clay mud at 160°F.

The loss of sealing ability shown by the silicate mud at higher temperatures appears to be due to the fact that this mud contains no colloidally dispersed material. Since the sealing of the filter cake must be accomplished by plugging the pores of the cake with fine particles (not colloidal) of clay and bentonite, a decrease in the viscosity of the liquid therefore causes a great increase in the volume of filtrate that can pass before the filter cake is plugged. We have determined the viscosity of the filtrate from the silicate mud tested (No. 2, Fig. 1) and found that the liquid is about five times as viscous at 80° F. as it is at 160° F. This is approximately the factor by which the filtration constant k is changed in this temperature interval, indicating that the loss of sealing ability is caused by the rapid increase in the viscosity of the liquid and the absence of colloidal sealing material.

Viscosity measurements that we have made on positive colloid muds and silicate muds at various temperatures have shown that the viscosity of silicate mud increases much more rapidly than that of positive colloid mud when the temperature is decreased. In going from 135° to 77° F. the viscosity of the silicate mud is almost doubled, while the same temperature change causes an increase of only about 50 per cent in the viscosity of the positive colloid muds, as measured with the Stormer viscosimeter.

A rather serious objection to the use of silicate mud is based on the effect of such a mud on electrical logs or well surveys. In order to obtain correct results with electrical logging apparatus, it is desirable to use a mud that has approximately the same electrical resistivity as the formation drilled; that is, for shale formations, about 2 ohms per meter cubed. The results of resistivity measurements given in Table 6 show that the resistivities of typical silicate muds are actually less than one tenth of the desired value. For this reason it is to be expected that surveys taken in holes filled with these muds will be distorted and relatively inaccurate, and this conclusion is borne out by the experience of operators. On the other hand, positive colloid muds have resistivities that lie between those of ordinary aqueous muds and the resistivity of shale, so a hole filled with positive colloid mud should yield accurate, undistorted electrical logs.

The initial cost per barrel of the positive colloid muds is about 25 per cent

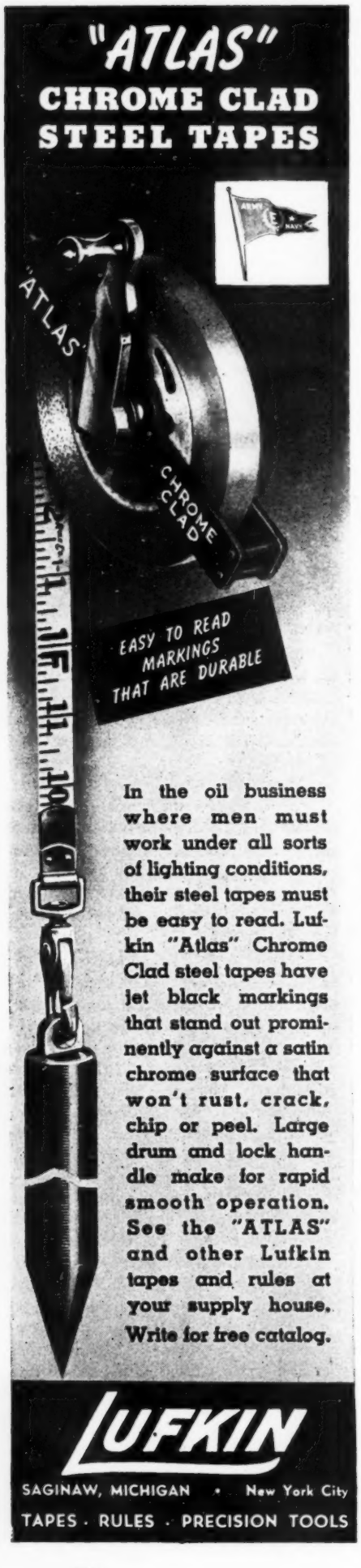
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TABLE 6

Electrical resistivities of drilling muds at 77° F.

Mud No.	Description of mud	Type of mud	Resistivity, ohms per meter cubed
1	Resistivity most desirable for electrical logging of shale		Approx. 2.00
2	W. W. Smith No. 1, Brazoria County, Texas	Silicate	0.18
3	Minnie Brown No. 1, Alice, Texas	Silicate	0.19
4	No. 2, Table 4	Positive colloid	3.3
5	Stewart-Dickinson No. 5, Dickinson, Texas.	Aqueous	6.5
6	Wells No. 1, Clay City, Ill.	Aqueous	4.0

higher than the cost of silicate muds. Because of the superior sealing properties of the positive colloid muds, especially at high temperatures, the loss of drilling fluid to the formation should be so much less than the loss of silicate fluid that the difference in initial cost would be more than offset by the saving of fluid during drilling.

Because of restrictions on the use of dyes, positive colloid muds have not yet been tested in the field. At the close of the war there should be a large potential production capacity for dyestuff intermediates and dyes because of the vast increase in number and output of nitration plants. This may make it possible to prepare positive colloid muds in large volumes at a cost somewhat less than the cost of silicate muds.

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Reservoir Performance*

By JOHN J. MULLANE
The Carter Oil Company

THE necessity and desirability of operating petroleum reservoirs at the maximum efficiency practicable have occasioned the development of the growing science of reservoir engineering. The proper development and control of oil reservoirs form the subject matter of this field. During recent years, the work of a number of petroleum technologists has resulted in the establishment of certain basic principles, upon which modern thought on oil reservoir performance is based. It is the purpose of this paper to present these principles and to show by actual examples how they may be effectively utilized.

Reservoir performance. Three definite modes of performance of petroleum reservoirs have been recognized: (1) Dissolved gas drive, (2) gas cap drive, and (3) water drive. These are defined according to the sources of energy, or drive, under which the oil is moved through the producing formation into the well. It is important to know the outstanding features that characterize each of these types of operation, because, in a great many instances, it is possible to make a choice between them at an early stage of the development of a field. In particular, what must be known are the criteria by which one kind of performance may be distinguished from another, the consequences that result from a specific choice, and the operating procedures that must be followed to achieve the type of performance desired. The character of each type of drive will be briefly outlined and illustrated with examples taken from field experience.

Dissolved gas drive. Where the sole source of energy available or utilized to produce the oil from the reservoir is in the gas dissolved in the oil, the reservoir is defined as being in operation under a dissolved gas drive. This type of performance is characterized by continuous and rapid decline in reservoir pressure, paralleled by a steady decline in well potentials, and it exhibits a distinctive gas-oil ratio behavior, in which the gas-oil ratio rises steadily to a maximum value several times the original ratio and thereafter declines. The recovery to be expected from this type of mechanism ranges from 15 to 40 per cent of the oil originally in place.

The conditions which make this method of operation mandatory are:

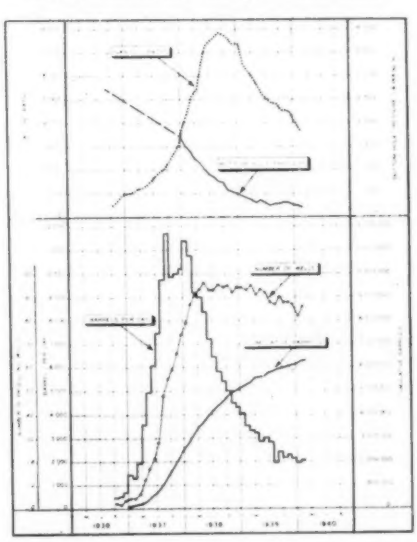
(a) Flat structure, usually with substantial stratification or low vertical permeability, obviating the possibility of appreciable gravitational segregation of gas released from solution.

(b) Absence of a free gas cap or of a water body that could move into the oil reservoir.

(c) High rate of production, substantially exceeding the ability of any water present to advance into the reservoirs, or the ability of a free gas cap, if present, to expand efficiently.

In Fig. 1 is shown the production statistics for the Gloyd-Mitchell zone of the Rodessa field, Louisiana. This reservoir is a nearly flat extension of the main Rodessa structure. Production is from two intervals in the Gloyd zone, found at 5900 ft. The upper one of these, a sandy lime, is known as the Mitchell sand, and the lower section is predominantly oolitic lime and is designated as the Lower Gloyd. The oil produced from this field has a suface gravity of 42° to 43° A. P. I., and the solution gas was originally 627 cu. ft. per bbl. under the original pressure of 2400 lb. per sq. in. No free gas was originally present in this section, and there has been no evidence of water drive noted. The wells completed in this zone were produced at high rates and experienced a rapid decline in production. The availability of reasonably accurate data on this field has made possible the presentation of an excellent practical example of the salient features of this type of drive and provides a satisfactory check on the theoretical expectancy. It will be noted that the production and pressures both suffered a steady, rapid decline, and the gas-oil ratio history has exhibited behavior typical of this type of drive.

Fig. 1. Graphical statistics, Rodessa field, northwest Gloyd extension



The ultimate recovery from this zone has been estimated to be 20 per cent of the original oil in place. This low recovery is in accord with the expectation for this type of drive. This conclusion is based on the study of a number of fields which have been wholly, or largely, produced under this mechanism, and includes fields producing from the Chester sands in Illinois and the Bartlesville sand in Oklahoma. While recoveries as high as 40 per cent may be anticipated under this drive, by far the majority of cases reviewed showed recoveries that ranged from 20 to 30 per cent.

Gas cap drive. Under this type of drive or recovery mechanism, a distinct free gas area, either originally present or created, expands, or is caused to expand by injection of gas, thus encroaching downward into the oil zone and displacing oil downstructure. Here the energy in the system in the form of solution gas is augmented by that of the expanding gas cap and, under proper conditions, will be further enhanced by the force of gravity. In this type of drive, the pressure may be either maintained at approximately its original value or maintained under a controlled decline. At the same time, the producing rates are maintained at more uniform levels than is possible under ordinary dissolved gas drive operation. The free gas in fields of this kind is virtually all segregated in the gas cap zone, and the gas-oil ratio of all wells, except those close to the gas-oil contact, remains at a low value. The gas-oil ratio of wells close to the gas-oil contact continues to rise until largely free gas is produced, at which time they are closed to production. The ultimate recovery to be expected from this recovery mechanism will range from 40 per cent to possibly as high as 80 per cent of the original oil in place.

The conditions that favor this type of operation are:

(a) The sand must have high permeability, since for practical purposes the prevention of channeling and by-passing of gas, both that evolved from solution and that previously in the gas cap, would be very difficult if this condition were not fulfilled.

(b) Pronounced structure is usually necessary to aid gravitational segregation.

(c) The sands must be continuous and reasonably uniform to permit thorough displacement of the oil as the gas cap expands through the oil body.

(d) Some restriction of oil withdrawal rate is necessary to prevent gas channeling and bypassing.

*Presented before American Petroleum Institute, Mid-Continent District Division of Production, Tulsa, Oklahoma, May 25-26, 1944.

(e) Careful gas conservation is usually necessary if the full use of the displacing ability of the gas cap is to be enjoyed. In some cases, this may require return of gas to the crest of the structure.

As an example of this type of operation, the production statistics for the Mile Six pool in Peru are shown in Fig. 2. This field, which produced a 40° A. P. I. gravity oil from the Parinas sandstone, met the requirements for gas cap drive operation. It has good porosity and permeability and pronounced structural relief, as is seen on the structure map in Fig. 3. Throughout operations, there has been a high degree of gravitational segregation, and the volume of gas returned to the sand up to 1940, amounted to 127 per cent of all the gas produced from the field. The effect of this on the downward migration of the gas-oil contact is graphically illustrated on the map in Fig. 3. It will be observed in Fig. 2 that the pressure has been maintained almost at the original level and that gas-oil ratios have held remarkably constant. Practically all of the oil produced from this pool to date has been obtained by natural flow, and the indicated recovery efficiency is approximately 50 per cent. This relatively high efficiency is typical of this recovery mechanism.

Water drive. When, in a petroleum reservoir, the principal means for the displacement of oil from a producing horizon into the wells is the encroachment of edge water or bottom water into the oil zone, under the influence of the pressure gradients created by the production from the wells, the reservoir is said to be operating under a water drive. The chief operating characteristics of this type recovery mechanism are the maintenance of reservoir pressure at relatively high levels throughout the course of production, the retention of productivity by the wells, and operation at low gas-oil ratios. The degree to which these ends are attained depends on the relation that exists for a particular reservoir between the rate at which oil, gas, and water are removed from the reservoir and the rate of influx of water. The recovery of oil under this mechanism will range from 40 per cent to as high as 80 per cent, depending on the properties of the reservoir and its contained fluids.

Water drive may come about in two ways: (1) Simple artesian flow, which is comparatively rare, and (2) as a result of the expansion of the water in that part of the reservoir outside the oil zone. The requirements for a satisfactory water drive are as follows:

(a) The oil body must be in good communication with a permeable and continuous water bearing sand (usually the regional continuation of the oil sand itself) of considerable areal extent, or outcropping at a reasonable distance.

(b) The permeability of the sand must be fairly high, so that the rate of water advance can be sufficient to be of benefit within practical time limitations. Similarly, oil viscosity must be reasonably low.

(c) The sands in the oil reservoir proper must be reasonably continuous and uniform, so that effective flushing may be obtained.

(d) Rate of fluid withdrawals must be restricted to a level commensurate with the ability of the water to advance evenly into the oil sands, if maximum effectiveness of the flushing action, through avoidance of channeling and bypassing by the encroaching water, is to be realized.

The behavior of the Dix pool (Fig. 4) in Jefferson County, Illinois, furnishes an excellent example of a field operated under the water drive recovery mechanism. The reservoir here is a small anticlinal dome in the Bethel sand, and the water bearing part is continuous in all directions from the pool for a distance of at least 20 miles. Throughout the life of the field to date, the pressure in the reservoir has been maintained above the saturation pressure (270 lb. per sq. in.) of the oil. It is of interest to note that, in the past year, there has been a buildup in pressure of 19 lb. per sq. in. The water encroachment has been, and remains, uniform, the water contours following the structure very closely. It is too early in the life of this operation to forecast accurately the recovery efficiency for the reservoir, but preliminary estimates place it in the neighborhood of 40 per cent. This is to be compared with East Texas, which is at the opposite extremity of the efficiency range. At East Texas, the recovery has been estimated, both from cores taken in the flooded zones and from careful calculations, to be approximately 80 per cent. Other water drive fields, such as Magnolia, Arkansas, producing from the Smackover lime, and North Searight, Oklahoma, producing from the Ordovician Wilcox sand, lie in between these extremes. In general, there is to be found a relation between the recovery efficiency and the properties of the reservoir and its contained fluids. In particular, recovery is affected by the permeability of the reservoir and the viscosity of the oil, and, in a more general way, the recovery will be affected by the uniformity, or lack of it, in the reservoir. Further, there are capillary forces at the oil-water interface which exert a definite,

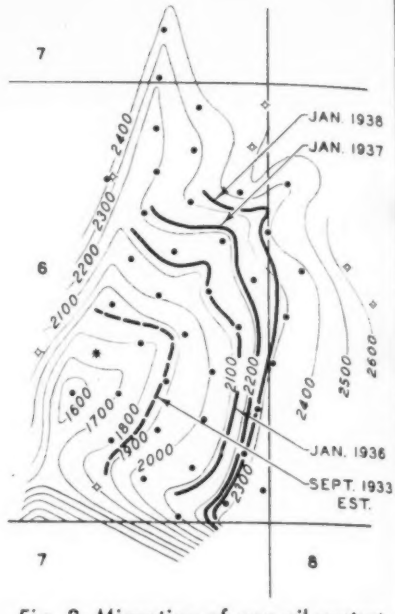
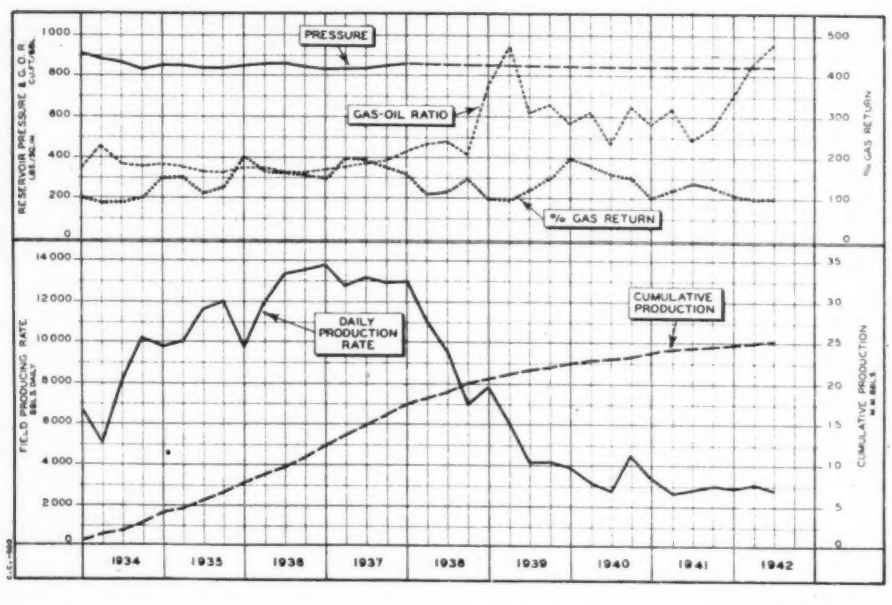


Fig. 3. Migration of gas-oil contact, Mile Six oil pool

Fig. 2. Operating data, Mile Six pool



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but as yet not measured, effect on the recovery. At Dix, the reservoir sand has a permeability of 80 millidarcys, and the reservoir oil viscosity is 2.5 centipoises, whereas at East Texas, the permeability of the Woodbine sand averages 1500 millidarcys, and the reservoir viscosity is low, approximating 1.5 centipoises. In general, however, while the recovery under water drive may vary from 40 to 80 per cent, depending on reservoir conditions, for any particular reservoir water drive can be expected to yield a higher recovery than simple dissolved gas drive. To return to the example given above, normal recoveries by simple gas expansion in the Bethel and other Chester Series sands in the Illinois Basin average 20 to 25 per cent, whereas recovery from this sand under water drive will approximate 40 per cent.

Comparative behavior. To summarize the principles observed above, we may draw the following conclusions, with regard to the comparative behavior of these three fundamental recovery mechanisms:

1. The simple dissolved gas drive mechanism operates with a rapid depletion of pressure, whereas in the gas cap drive or in the water drive, pressure is maintained at relatively high levels, if the proper operating practices suitable to each are observed.

2. In the dissolved gas drive operation, there is an extremely rapid decline in the production rate, due to the rapid depletion of energy, compared to the retention of productivity at higher levels in the other recovery mechanisms.

3. Each type of drive shows a distinctive gas-oil ratio behavior. In Fig. 5 there is shown typical gas-oil ratio behavior of the two types of gas drive recovery. It will be noticed that, in the dissolved gas drive, there is a very rapid depletion of the gas in solution, whereas in the gas cap drive, particularly under those conditions favorable to gravitational segregation, the gas is conserved in such a manner as to be of material assistance in promoting higher ultimate recovery, and the gas-oil ratio throughout the major part of the life of the operation is maintained at a low level. It will be observed that, where gravitational segregation of oil and gas is not effective, the gas cap drive mechanism reverts to a behavior lying between that of simple dissolved gas drive and gas cap drive, coupled with complete segregation. Lack of segregation will result in the production of excessive amounts of gas, rather than in its retention in the reservoir. Such a condition may be encountered in very flat structures that afford little opportunity for the control of the free gas, in tight sands, or in repressuring operations, in which gas injection is made throughout the oil acreage. In water drive operations, where properly controlled, the gas-oil ratio is also maintained at low levels and, under some conditions, can be maintained at solution gas-oil ratio over virtually the entire producing life of the pool. This is particularly true in such cases as the Dix pool, cited above, in which the reservoir oil was initially undersaturated. In those cases where the oil is initially saturated at the original bottom hole pressure and a free gas cap is present, adequate control of gas-oil ratio and the avoidance of the production of gas from the gas cap can usually be attained by proper well completion and production techniques.

4. With regard to ultimate recovery, these types of performance are again divided into two distinct groups: A dissolved gas drive with a generally low recovery and the gas cap drive and water drive with generally higher recoveries. Experience and study have shown that the dissolved gas drive mechanism is inherently the most inefficient means of recovering oil. Laboratory experimental work[1] on the expulsion of oil from sands through the medium of dissolved gas drive has shown that, when the gas saturation in the sand reaches approximately 10 per cent of the pore volume, the flow of gas, hence the gas-oil ratio, increases rapidly, and when the gas saturation reaches approximately 20 to 35 per cent of the pore volume, the production of oil becomes negligible. In other words, the recovery of this type of drive, expressed as per cent of pore volume, will be, generally, in the neighborhood of 25 per cent. It is apparent, of course, that the percentage recovery, in terms of the original oil in place, will vary with the percentage of connate water in the sand. The recovery efficiencies, then, in dissolved gas drive, depends only on the composition and properties of the reservoir and its contained fluids. In the case of gas cap drive, coupled with gravitational segregation, the examples cited above illustrate the higher recoveries obtained under this merchanism. To capitalize to the greatest possible extent on this type of drive, it is often desirable to augment the free gas originally present by injection of at least all of the produced gas, to maintain the pool energy at a high level. The inherent efficiencies of gravitational segregation and gravity drainage alone are graphically illustrated by the behavior of the Oklahoma City field, which produces in the Ordovician Wilcox sand. At the time the pressures had reached 100 lb. per sq. in., only 23 per cent of the original oil in place had been recovered. Although the pressure in this reservoir had been rapidly depleted, the recovery to January, 1941, was 35 per cent of the estimated oil in place and is expected to reach 50 per cent to 55 per cent ultimately by primary means.

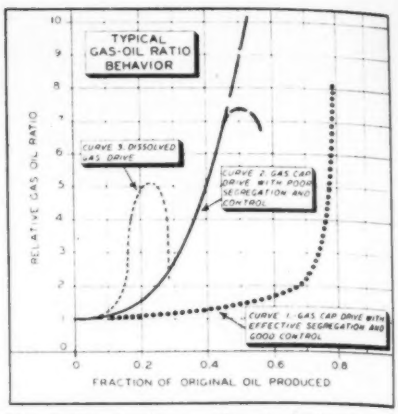
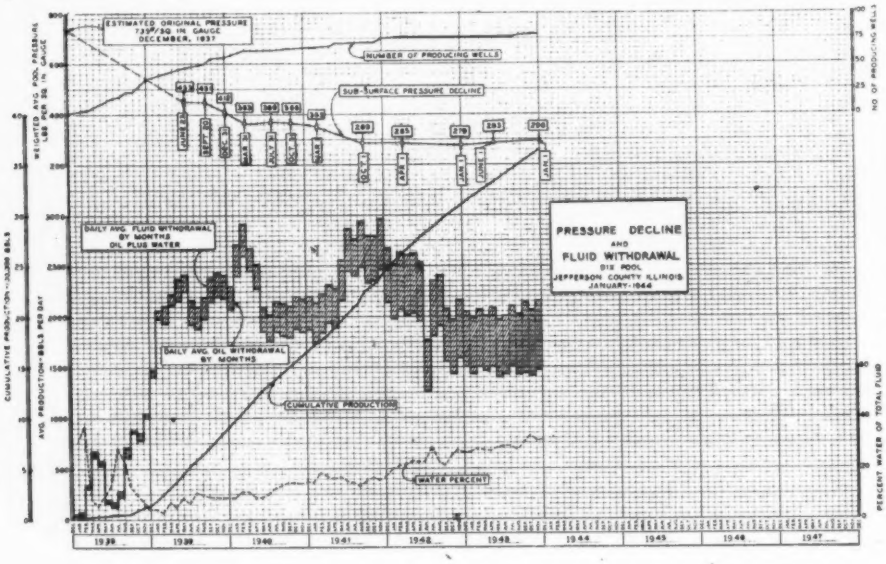

TYPICAL GAS-OIL RATIO BEHAVIOR
CURVE 3. DISSOLVED GAS DRIVE
CURVE 2. GAS CAP DRIVE WITH POOR SEGREGATION AND CONTROL
CURVE 1. GAS CAP DRIVE WITH EFFECTIVE SEGREGATION AND GOOD CONTROL
RELATIVE GAS OIL RATIO
FRACTION OF ORIGINAL OIL PRODUCED

Fig. 5. Typical gas-oil ratio behavior of the two types of gas drive recovery

Fig. 4. Pressure decline and fluid withdrawal, Dix pool, Jefferson County, Illinois



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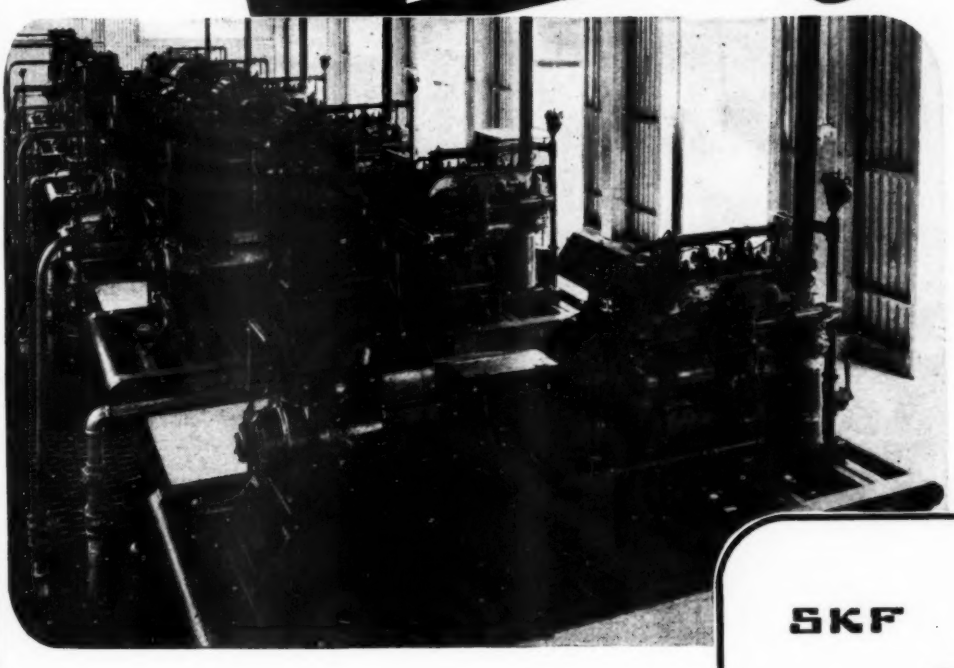

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The difference between the ultimate recovery and the recovery at the time of pressure depletion can be attributed largely to the mechanism of gravitational segregation. In the updip part of the structure on the east flank of the pool, cores taken in that part of the sand taken over by gas have measured residual oil saturations as low as 20 per cent. It is to be noted, however, that, in this pool, where the energy was not maintained, as was the case in the Mile Six pool, much of the oil to be recovered will be produced at relatively low rates. Further, the sand quality in the Wilcox horizon definitely represents the most favorable conditions that could be encountered. In general, in this type of field, both from an economic point of view and from the point of view of recovery efficiencies, the maintenance of reservoir energy through the injection of gas is to be preferred.

The low residual saturations obtainable under water drive have been determined by the analysis of cores taken from the Woodbine sand at East Texas, in that part of the producing horizon already flooded out by water. Further testimony to this is obtained from the experience of water flood operations, in which, in the Oklahoma-Kansas shallow area, residual saturations slightly below 25 per cent of the total pore volume actually flooded have been obtained in the Bartlesville sand. While these figures definitely represent the maximum efficiency obtainable, an analysis of other water drive operations definitely establish the superiority of this type of recovery mechanism over simple depletion type operation.

5. In addition to the obvious advantages involved in greater ultimate recoveries, the gas cap and water drive mechanisms offer also definite advantages from an operating point of view. In many cases, operations under these kinds of drives can be conducted with most, if not all, of the wells in the field producing by natural flow throughout most of their life, whereas under dissolved gas drive, the flowing life of the wells is usually brief. Particularly in water drive operations, there will be some cases where, even though the field is produced at efficient rates, it will be necessary to resort to pumping production. This will occur in fields where the oil is so greatly undersaturated that there is insufficient energy to flow the wells. Further, it is also to be noted that, where water production in the wells reaches a range from 20 to 50 per cent of the fluid produced, it will usually be necessary to resort to pumping.

From the foregoing points, the superiority of gas cap drive and water drive over simple dissolved gas drive is definitely established. In actual practice, of course, many reservoirs are found to be operating under more than one form of drive; however, some one recovery mechanism usually dominates, or can be made to dominate, the performance of the field. The major problem, then, that confronts the operator and the reservoir engineer when a field is opened to development is to establish what type of drive is present, or what type of drive is to be utilized in the operation of the reservoir. It is apparent that only when no other alternatives are possible will dissolved gas drive be employed, if the maximum efficiency is to be obtained.

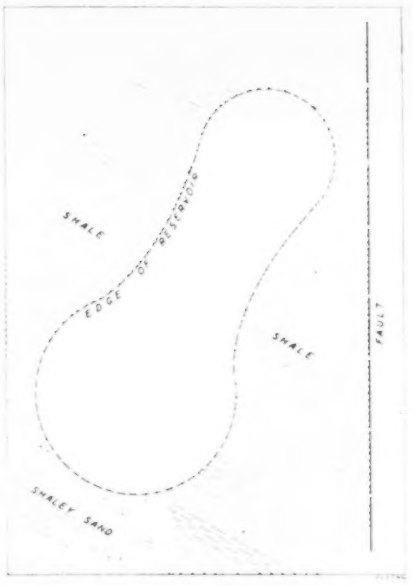


Fig. 6. Schematic diagram of a reservoir

Identification of the type of drive. Often, excellent indications of the type of drive that may be anticipated in a given field can be obtained from a study of the geological data that is available concerning the general area in which development is planned. The geologic information required for preliminary study directed to the identification of the type, or types, of drive possible are given in the following statements:

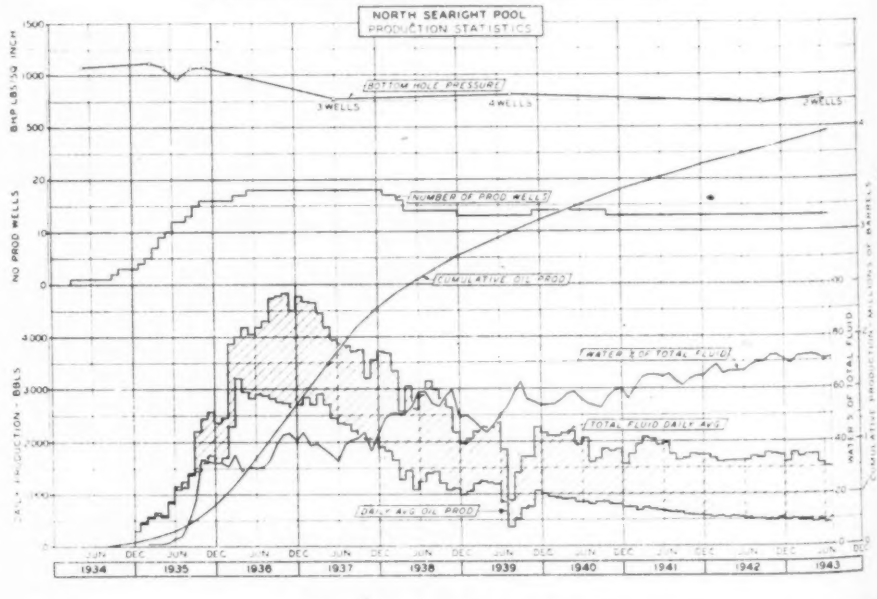
1. The nature and extent of the horizon to be exploited should be known. In this connection, it is desirable to know whether the prospective producing horizon is reasonably continuous over a large area, such as, for example, the Smackover lime, or whether it consists largely of more or less isolated sand bars, such as the Waltersburg sand in Illinois or the Bartlesville sand in Oklahoma. From these data, it can be deducted whether or not there exists a sufficiently large body of water in connection with the oil reservoir to sustain a water drive. In general, what is required for this purpose is a continuous water bearing horizon, extending from 10 to 20 miles from the edge of the pool.

2. The presence or absence of major faults should be noted. If the accumulation is against a fault, or near a major fault, the degree of water drive attainable will be reduced. This will tend to limit the rate of production that the water drive can sustain.

3. The continuity of porosity and permeability in the horizon should be determined as soon as possible. This information affords further indications of the possibilities of the presence or absence of a water drive.

From these preliminary data and the subsurface geologic data obtainable from early wells, which data define the nature and extent of the oil reservoir, the structural relief, the presence or absence of an original gas cap, and the location of the water table, if one is found to be present, an excellent preliminary picture of the possibilities may

Fig. 7. Production statistics, North Searight pool


NORTH SEARIGHT POOL
PRODUCTION STATISTICS
BOTTOM HOLE PRESSURE
3 WELLS
4 WELLS
3 WELLS
NUMBER OF PROD WELLS
CUMULATIVE OIL PROD
WATER % OF TOTAL FLUID
TOTAL FLUID DAILY AVG
DAILY AVG OIL PROD
BHP LBS/SQ INCH
NO PROD WELLS
DAILY PRODUCTION - BBLS
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be set up. This can be well illustrated by the following example. In Fig. 6 is shown a schematic diagram of an actual reservoir. This oil accumulation was in a sand bar, extending for several miles on a northeast-southwest trend. The location of a major fault running in a north-south direction to the north and east of the field, as shown in the diagram, was known. A few dry holes in the shale zone were drilled, defining the edge of the reservoir and also the continuity of the permeability and porosity on either side of the pool. Porous and permeable sand was found only to the southwest of the pool. From these data, then, it can be immediately concluded that only a very limited water drive is possible in this field. If, for example, the sand had been continuous in all directions around the pool for a distance of several miles, such as was the case in the Dix pool, previously cited, the possibilities for a water drive would have looked favorable.

Immediately upon completion of the first well, there should also be made a number of physical measurements, which will be of value in making an engineering study of the pool and in identifying the type of drive to be employed. Included in these are electric logs, core analyses, and bottom hole pressure and bottom hole sample data. With these geologic data and the physical measurements made during the early development of the pool, it will usually be possible to tell reasonably early in the life of the pool whether or not a satisfactory water drive exists. If a water drive can definitely be ruled out on the early data, the possibilities for gas cap drive can usually be determined as soon as sufficient wells have been drilled to define the properties of the reservoir, such as structural relief, porosity, permeability, and degree of stratification, and the extent of any gas cap found to be present. In many cases, there will be found distinct possibilities for the avoidance of operation under dissolved gas drive. In general, until such time as a decision on the type of drive to be employed has been made, conservative producing rates should be employed, in order to avoid doing harm to the reservoir through the loss of energy, which may be difficult to retrieve.

Reservoir control. It has been pointed out that the first problem in the control of the performance of a new reservoir is the absolute avoidance of the use of a dissolved gas drive as the recovery mechanism, if it is at all possible. Further, it has been stressed that conservative producing rates should be employed, until such time as the field is adequately explored and defined and the type of recovery mechanism to be used is identified.

In a gas cap drive, usually, the primary problem is the control of gas production. In this case, the rate of production must be consistent with the rate at which effective segregation of the gas and oil can take place. Further, there must be maintained a uniform advance of the gas-oil contact downstructure as the gas cap expands and the production of gas from the gas cap must be held to a minimum. Where pressure is being maintained by gas injection, the rate of withdrawal must be balanced with the rate of injection of gas. Excessive rates of production by individual wells in a field of this kind create high gas saturations in the sand adjacent to the well bore and can create serious problems of gas channeling, particularly in wells in the neighborhood of the gas-oil contact. Further, production at excessive rates in fields producing under this type of drive does not permit taking advantage of the benefits to be obtained from the gravitational segregation of oil and gas in the reservoir, with its attendant high liquid saturations and high well productivities in the downstructure part of the reservoir. In outline, then, the proper producing procedure for a reservoir of this type is the production of oil at such rates as to minimize free gas production and gas channeling and to maintain a uniform encroachment of the gas-oil contact downstructure, highest degrees of segregation of oil and gas, and a maximum liquid saturation in the producing horizon downstructure. Where possible, the return of produced gas to the reservoir should be considered, to maintain reservoir energy, low fluid viscosities, and more uniform producing rates.

In water drive operation, there appears every type of control problem likely to be found in any reservoir. Pri-

Fig. 8. North Searight pool, Keokuk area

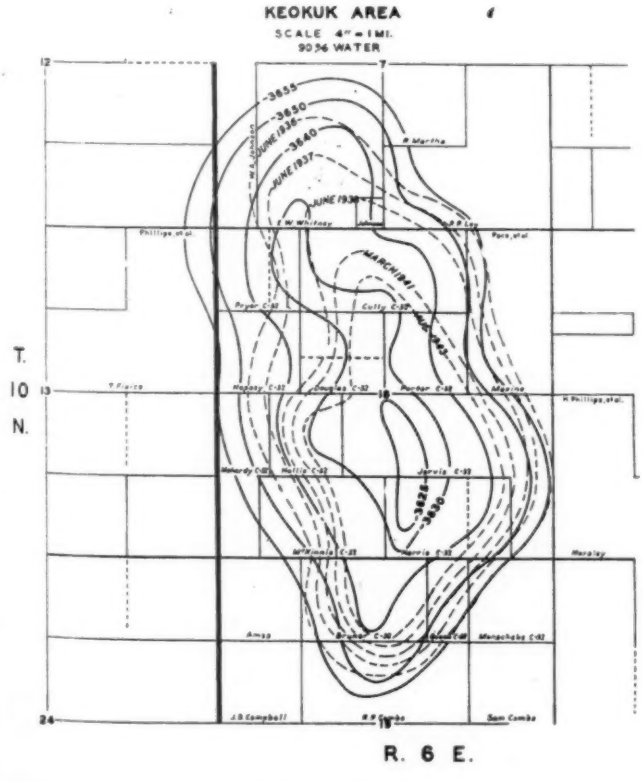
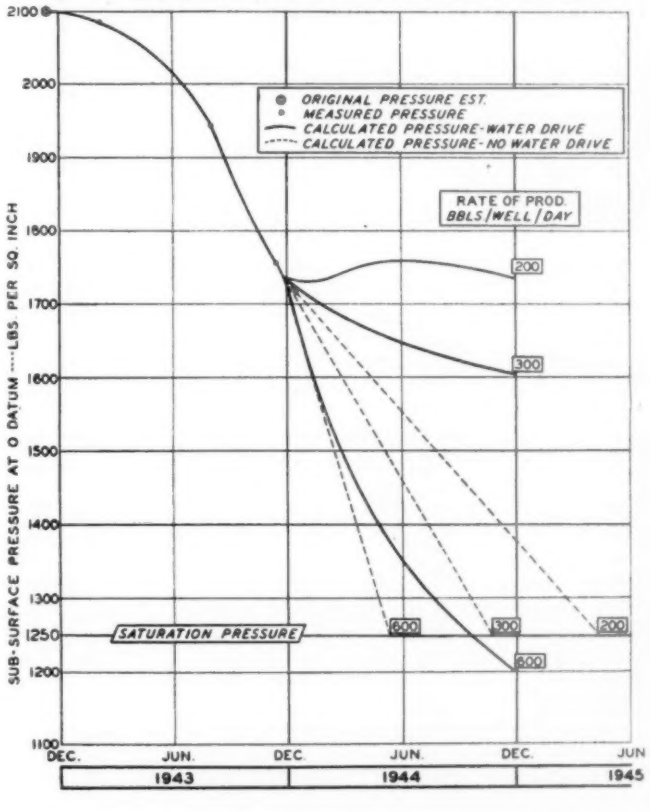


Fig. 9. Comparative pressure behavior, Elk Basin field



mary problems encountered in fields of this kind are the control of producing rates at such levels as to maintain a balance or a favorable ratio between withdrawals and water influx, the maintenance of a uniform encroachment of the water, and the control of water and gas production.

In Fig. 7 are shown the production statistics for the North Searight pool, Oklahoma, another typical water drive operation. Production in this field is from the Wilcox sand. Here, through the medium of proration, producing rates have been such as to maintain a balance between fluid withdrawals and influx of water into the reservoir, such that pressure may be maintained at a high level. Moreover, as will be seen from Fig. 8, there has been a uniform movement of the water table upstructure. This feature is desirable, in order to attain a uniform displacement of oil from the sand in that part of the reservoir flooded by water.

The importance of effective control of the rate of production from a reservoir, particularly in the early stages of development, is graphically illustrated by the behavior of the Elk Basin field, which produces from the Tensleep sand in Wyoming and Montana. From geologic considerations and from the behavior of another nearby Tensleep reservoir, there is reason to believe that a water drive of some magnitude may be present. However, at the rates of production that prevailed in the past, there has been a very rapid decline in pressure, and engineering study has shown that, at these rates, it is impossible to tell whether or not a water drive exists. The calculations shown in Fig. 9 illustrate this problem. In the study of the behavior of this reservoir, the pressure history to be anticipated was calculated on the basis of two assumptions: First, that a water drive exists; and, second, that no water drive exists and the production is due solely to the expansion of oil and its contained gas within the boundaries.

Important tools for the solution of problems of this kind have been developed by Muskat[2], Bruce[3], Schilthuis[4] and Katz[5]. The most interesting and important feature of the calculations shown in Fig. 9 is that, at the high rate of production of 600 bbl. per well day, so far as pressure behavior was concerned, there is no distinction between water drive and simple depletion operation. Under these conditions, a satisfactory decision as to the type of drive possible in this field could not be made, and, in the meanwhile, there was occurring a rapid depletion of reservoir energy. It will be observed that, at the lower rates of production, there is afforded an opportunity to make the necessary distinction and also to maintain the energy of the reservoir at a high level. This latter feature is, of course, of importance, whether or not a water drive materializes. If it should fail to materialize, this high energy level will be of value, in order that the maximum benefits of a gas cap drive may be employed. This reservoir is a steeply folded structure, has good permeability, and the crude oil at the present pressure levels has a relatively low viscosity. Thus, it is seen that, if the water drive fails to be of a commercial magnitude, there are good possibilities that a form of gas cap drive, or pressure maintenance through the medium of gas injection, can be employed to advantage. This pool study presents a striking example of the alternatives that are presented in the selection of a recovery mechanism, when an engineering study of the reservoir is made in its early life. In particular, the opportunities for the avoidance of the adoption of dissolved gas drive are stressed.

A problem of particular importance in water drive reservoirs is the control of water production. This is not, alone, important from the point of view of individual well performance, but also from the point of view of the performance of the reservoir as a whole, for, insofar as behavior of the reservoir is concerned, the withdrawal of a barrel of water has just as great an influence on the pressure behavior and other features of the operation as the withdrawal of a barrel of oil. There are three methods by means of which the production of water can be controlled. These are:

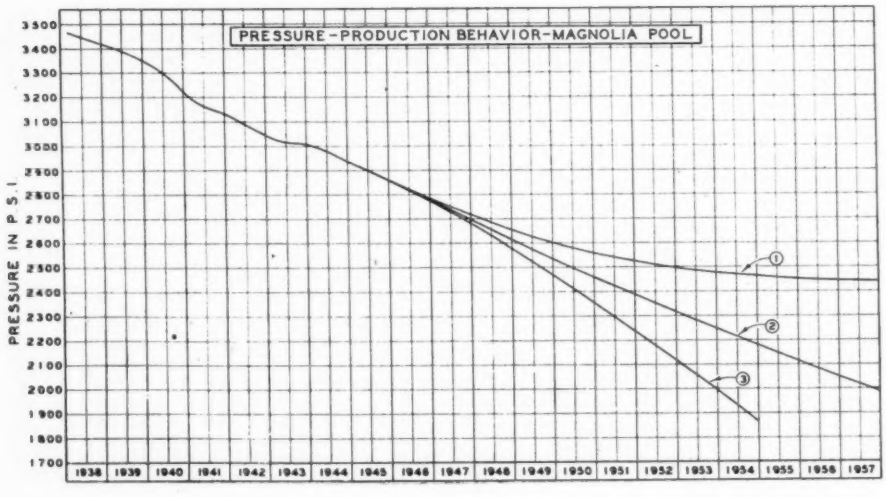
1. Mechanical methods, such as plugging back and the use of small bore pumps to facilitate uniform withdrawals.
2. The injection of water produced back into the horizon from which it was taken.
3. The control of producing rates.

As the mechanical methods referred to are not properly a part of reservoir engineering, they will not be further discussed here. However, particular attention is directed to the importance and availability of these techniques for the control of water production.

Attention has been focused recently on the return of produced water to the horizon from which it was taken. Application of this technique has already been made at East Texas, and, at the present time, application of this method is under consideration in the Magnolia pool, Arkansas. The return of unavoidably produced water to the formation can be, under suitable circumstances, a means of reducing effective reservoir withdrawals and thus maintaining reservoir pressure, through the medium of which, gas is retained in solution, high liquid saturations are maintained in the reservoir, and the flowing life of the wells is extended. The results that may be anticipated at Magnolia from this kind of control are shown in Fig. 10. The calculated pressure production behavior is shown for three sets of conditions. Curve 1 shows the behavior to be expected if all water production is returned to the reservoir, the gas-oil ratio is maintained constant, and the production rate reduced 4 per cent per year. Curve 2 shows the behavior when all water is returned and the gas-oil ratio and producing rate are maintained constant. Curve 3 shows the expected behavior with no return of water to the formation, maintaining the same producing rate as in 2. It will be observed that the return of all produced water to the formation, coupled with moderate reductions in producing rate over a period of years, will sustain the flowing life of the wells in this pool indefinitely.

An interesting experiment along this general line is already being conducted in the Midway pool, Arkansas, which also produces from the Smackover lime. A review of this operation has been presented to the A. P. I. by Horner and Snow[6]. In this instance, fresh water

Fig. 10. Pressure-production behavior, Magnolia pool



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is being injected into the Smackover through wells on the edge of the producing zone. This experimental project has shown some degree of success as a means of controlling the pressure behavior of the field. This project, however, is to be distinguished from that contemplated for the Magnolia pool. In the Magnolia pool, there already exists a substantial water drive, and the injection of water into the Smackover, in this case, is an auxiliary production control, as well as a means of disposal of salt water, whereas the Midway pool did not have a water drive comparable in magnitude with Magnolia, and fresh water was injected primarily to augment the water drive. The interesting feature of this experiment is the practical demonstration of the fact that it is possible to influence the behavior of the reservoir by the injection of water.

The third method by which water production can be controlled is by the control of the rate of production. Much water produced in water drive fields, particularly where the structure is rather flat and where the producing section is relatively thin, is due to water coning. The theoretical treatment of this problem, for the case of a homogeneous sand, has been given by Muskat[7]. Most petroleum reservoirs, of course, are not homogeneous, but have tight streaks and shale breaks and other discontinuities distributed more or less at random throughout the producing section. The problem is, then, reduced to establishing the maximum differential at which the average wells in the field can be produced and not make water. This can be done by test data, or production data taken from selected wells scattered over the area of the field. These test data, combined with the theoretical rates calculated for the same wells on the assumption of a homogeneous sand, establish a factor for the relation of theory to performance for wells in the producing section. This factor can then be applied to the theory rate for the average well; i. e., a well having an average thickness of section above the water table and the average penetration, and thus determine the optimum producing rate at which production of water can be minimized. A similar technique can be used for the control of producing rates where the coning of gas is a problem. It is to be understood, of course, that, in fields of this kind, every effort is made in the completion of wells to take advantage of every natural barrier to the intrusion of water or gas. The intention of this brief review of the problem has been to demonstrate that there are methods available, or methods which can be adapted, for the solution of the problem of the control of producing rates in fields where gas and water production are a problem.

It is evident in this discussion on the control of reservoir performance that there is already available much technical knowledge and experience, which may be brought to bear upon the problem. Further, there are many technical developments which are, at present, under trial and many more lying dormant awaiting trial. Considerable advancement has already been made, and a considerable understanding of the problems involved has been attained.

Well spacing. Well spacing alone has, in the light of the advances made in the understanding of reservoir performance, been relegated to a position of secondary importance, insofar as the ultimate recovery to be obtained from a reservoir is concerned. At the present time, attention is directed to the operation of the reservoir as a whole, with the idea of making it yield the maximum amount of oil possible, rather than merely attempting to complete each individual well with the maximum potential attainable.

A thorough and complete analysis of field experience has shown that, at least over the range of well densities employed in this country; i. e., up to 40 acres per well, there is no significant increase in ultimate recovery to be obtained by increasing the well density. A theoretical investigation of this problem by Muskat[8] has shown that the physical ultimate recovery does not materially depend on the number of wells in the case of dissolved gas drive operation. With regard to economic ultimate recovery, it was shown that, where the rates of production at abandonment are low, say 10 bbl. per well day or less, or where the sand is reasonably permeable, there was no appreciable difference between the physical ultimate and the economic ultimate recovery. While it was not possible to assign practical significance to the numerical results obtained in this investigation, the qualitative conclusions drawn are believed to be significant.

A worthwhile observation with respect to reservoir drainage can be made from a study of the behavior of the Dill pool, Oklahoma, which produced by dissolved gas drive from the Hunton lime. This field was developed on 40-acre spacing. One well, however, the Dill No. 1, was originally completed in the Cromwell sand. After depletion of this sand lens, this well was deepened to the Hunton lime. The original bottom hole pressure in the Hunton Lime was 1725 lb. per sq. in., and the initial production of the Hunton wells averaged, after acid treatment, 1500 bbl. per day. When the Dill No. 1 was completed in the Hunton lime, it had an initial production of 101 bbl. of oil per day, and the bottom hole pressure was found to be 113 lb. per sq. in. This indicated stage of depletion was approximately the same as that in the offset wells, which had produced throughout their entire life from the Hunton lime. That the oil, as well as the gas, had been drained from this area was demonstrated by the fact that the gas-oil ratio of this well was comparable to the gas-oil ratio for the remainder of the field, indicating comparable oil and gas saturations throughout the reservoir. The ultimate recovery to be expected from this well is 40,000 bbl. of oil, compared with approximately 160,000 bbl. of oil for the offset wells. From these and other similar observations of pools producing under dissolved gas drive, it is evident that the only consideration in which well spacing is of primary importance is in the proper exploration and definition of the reservoir. Insofar as the proper depletion of the pool is concerned, it is only necessary that sufficient wells be drilled to adequately develop the reservoir and obtain production at economic rates.

The primary problem in successfully draining a reservoir operating under water drive or gas cap drive will be the proper location of wells, rather than well spacing, as such. In general, it is obvious that, in a gas cap drive, it would be desirable to locate most of the producing wells downstructure, in which direction the expanding gas cap would tend to displace the oil, and conversely, in water drive fields, development would be concentrated upstructure to avoid unnecessary production of water and the drilling of unnecessary wells, which contribute little or nothing to the ultimate recovery of the field. As a purely practical matter, however, wells are usually drilled throughout the field on a somewhat regular pattern and are not confined to that portion of the reservoir where they would be most effective.

The number of wells required in a water drive or gas cap drive field is that which will permit the proper control of the movement of gas and water to accomplish uniform displacement. Further, sufficient wells should be drilled so that when the field is produced at an efficient rate, the production rate of individual wells should not be excessive; i.e., individual wells should not be produced at such rates that there is an excessive production of free gas or water, or that the rate of depletion of the sand in the immediate vicinity of the wells is materially greater than in the remainder of the reservoir. A well, or group of wells, operating at excessive rates in a reservoir of this kind can create a localized dissolved gas drive condition, which could affect the ultimate recovery from the reservoir as a whole and is a condition to be avoided.

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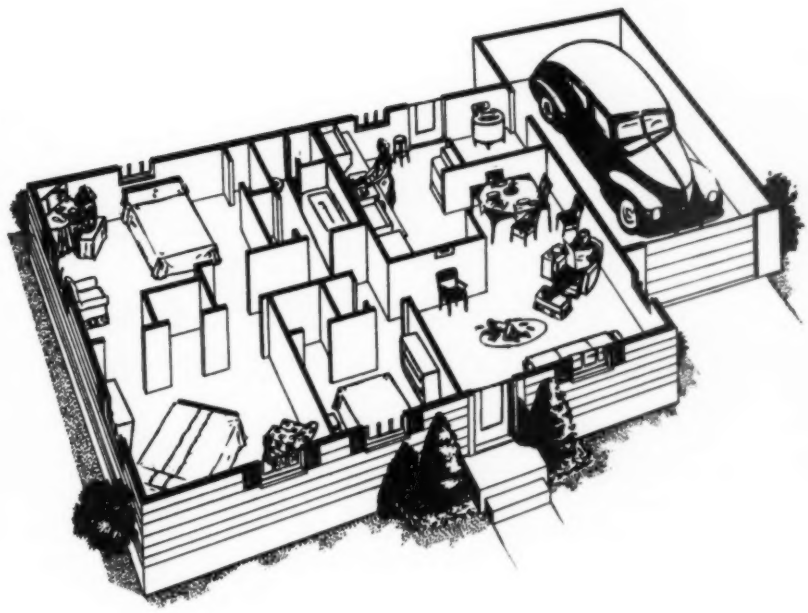

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The particular spacing to be used, then, in fields of these kinds, can only be properly determined at such a time as an efficient rate for the reservoir as a whole can be established. The implication of this statement is that it is prudent to develop a field on a moderately wide spacing, until such time as the reservoir is defined and the proper producing rate determined. If, then, further development is indicated, in order that proper control of the reservoir can be maintained, such additional wells as may be necessary can be drilled. By a procedure or plan of development of this kind, it will be possible to obtain the maximum recovery from petroleum reservoirs and to maintain efficient and economical operation.

Discussion. In the foregoing sections, the fundamental features of petroleum reservoir performance have been outlined and illustrated. Attention has been directed to the importance of making a thorough engineering analysis of the reservoir in the early stages of its development, and reference has been made to a few of the important theoretical and experimental studies which, together with the experience of the past, form the basis of the present knowledge of reservoir engineering.

While the details of the analysis of any specific reservoir are often somewhat difficult, particularly when it is considered that, due to the vagaries of nature, each reservoir presents new problems, the basic principles are essentially simple and of considerable generality. Variations in the nature of the reservoir appear to modify only the details of its history, rather than the fundamental character. The fundamental features of the performance are, in a large measure, in the hands of the operator and the engineer. As has been shown, it is possible to determine in advance or at an early stage of production in many, if not in most, fields, just what type of recovery mechanism is to be utilized. Accordingly, the broad, general outlines of the history of the operation can be laid out. Thereafter, what is required is the accumulation of accurate measurements of the properties of the system and accurate records of the production and performance, in order to maintain a detailed and uniform control of the operation. It is to be stressed that efficient operation of the reservoir means proper control of the entire reservoir and not merely parts of it. As has been stated by S. E. Buckley[9], good practice on one lease and bad practice on another does not necessarily average out to give a reasonably good average performance.

While there are unquestionably large gaps in our knowledge of the details of reservoir performance, a small capital of knowledge has been accumulated over the past decade, which, if intelligently and diligently applied, will serve to improve our understanding of these problems in the future and will be of economic advantage to all concerned in the development of the petroleum industry. Intensive research is being continuously carried on to improve further the methods of control and yield of oil reservoirs.

Acknowledgement. The author is particularly indebted to the joint progress report on reservoir efficiency and well spacing by the committees on reservoir development and operation of the Standard Oil Company (N.J.) Affiliated Companies and the Humble Oil and Refining Company, which was freely drawn upon in the preparation of this paper. Thanks are also due to the management of The Carter Oil Company for permission to publish the paper.

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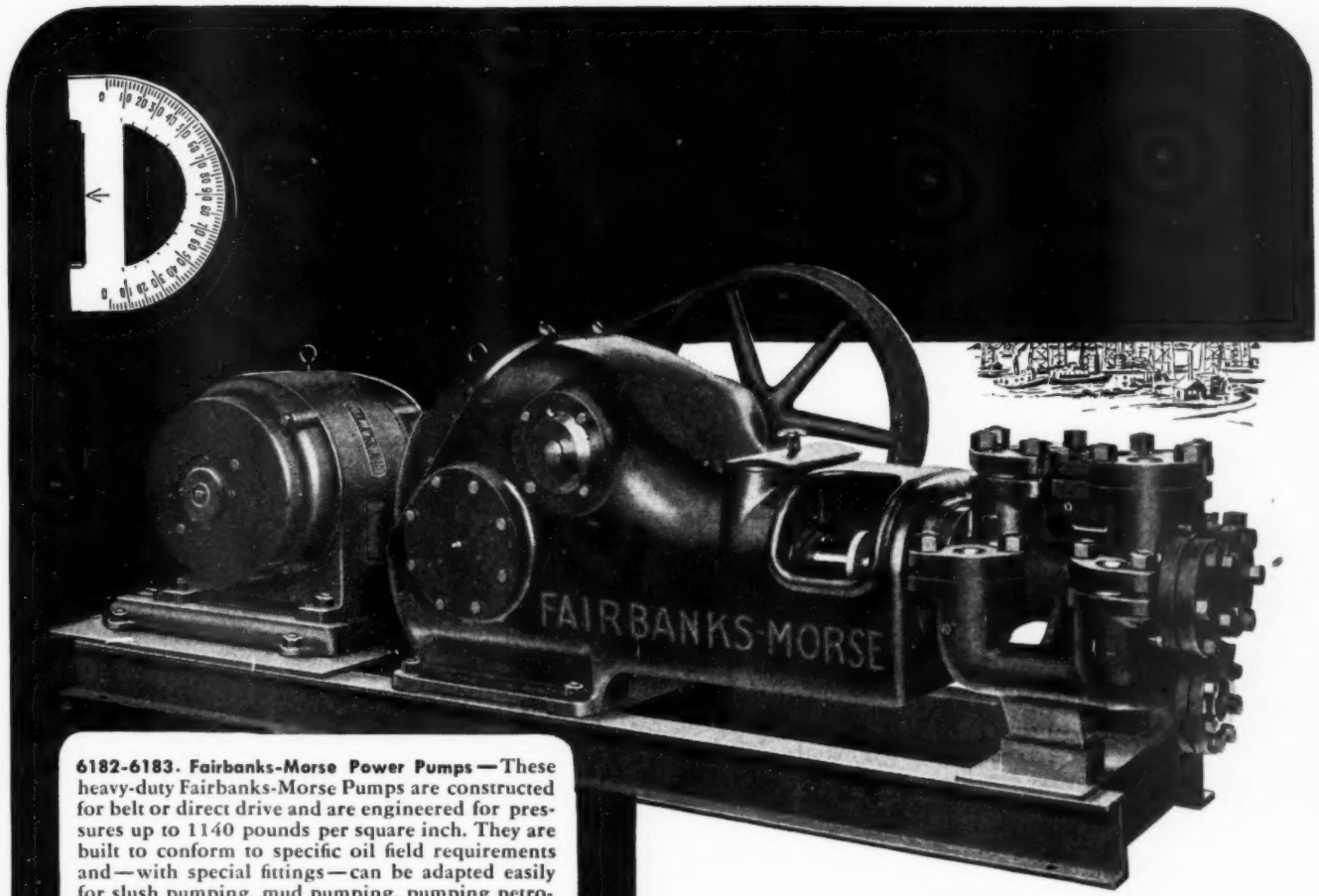

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High-Pressure Production Equipment Corrosion*

By THOMAS S. BACON, Research Engineer
Lone Star Producing Company

INTRODUCTION. The petroleum industry has recently realized the existence of a new problem occasioned by high pressure gas-distillate operations. This problem was first publicly described slightly more than a year ago. At that time it appeared that the problem was not widespread, but it has attained very important proportions during the past few months.

A paper presented before the Natural Gasoline Association of America Convention in Dallas in April, 1943, described internal corrosion of Christmas tree fittings that had been observed in the Opelika field, Henderson County, Texas.[1] This corrosion occurred on the internal surfaces of pipe, valves, and fittings in the Christmas tree assembly and was so severe as to have weakened some of the equipment almost to the point of failure. This particular type of corrosion appears to be unique in that it may be highly localized, causing serious weakening of one end of a length of pipe, while not affecting the other end appreciably.[2] It also occurs in the absence of any known corrosive agents with the possible exception of carbon dioxide. This particular form of corrosion is extremely unpredictable on the basis of present information and, in at least some instances, some wells in a given field will be entirely free from any sign of corrosion, while other wells will be corroded with extreme rapidity. To emphasize this unpredictability, the Tullos No. 2 well in Opelika field has been produced for several years with a total gas production of 5,225,000,000 cu. ft. to May 1, 1944. This well has shown absolutely no signs of internal corrosion of this type. On the other hand, the Tullos No. 1 well in the same field showed extremely serious corrosion of the Christmas tree in September, 1942, after producing 6,000,000,000 cu. ft. The Tullos No. 1 well has continued to show serious corrosion and some items of equipment have been replaced on this well after only three months of service. It should be emphasized that these two adjacent wells have been producing under conditions as nearly identical as may be expected in actual operation, yet one well has corroded badly and the other well is entirely unaffected. The average carbon dioxide content of the gas produced from the corroded well is 1.6 per cent, while the uncorroded well shows 1.5 per cent carbon dioxide.

The appearances of the corroded surfaces vary widely. Fig. 1 shows some typical surfaces with severe attack at points of high turbulence in the gas stream. It will be noted that the downstream section of one of the nipples is practically unaffected by corrosion. Fig. 2 indicates another form of corrosion in which the internal surfaces of the fittings are fairly smooth and the internal surfaces of the nipples are attacked only slightly, whereas serious weakening has been caused by removal of the threads on the nipples and by removal of the adjacent threads in the fittings. The appearance of some attacked surfaces might lead to the assumption that erosion plays an important part in the removal of metal. The experience of the Lone Star Producing Company has indicated that the removed metal is largely in chemical solution in the produced water in most cases. This experience and the fact that large pits covered with mechanically weak mill scale have been found adjacent to the roughened surfaces indicates that corrosion is probably the predominant cause of metal removal.

This form of corrosion is particularly dangerous because failure of the high pressure equipment involved might result in very serious property damage. Several flow lines have failed in service.[3] However, in each case of flow line failure that has been reported to date, it has been possible to close the well in before the Christmas tree was seriously damaged. Failure of a master valve under these conditions might conceivably make it impossible to control the well except by the slow and expensive process of drilling a directional well. The expense involved in drilling the directional well and the economic waste occasioned by the escape of reservoir fluids to the air and the possible retrograde condensation losses in the reservoir could easily be sufficient to absorb a considerable portion of the anticipated return from a recycling project.

The economic cost of this type of corrosion is also amplified when tubing fails in the well. Five strings of tubing have been reported as parting in the Cotton Valley, Louisiana, field in six months due to this corrosion.[3] The Union Producing Company has lost three strings of tubing in other Louisi-

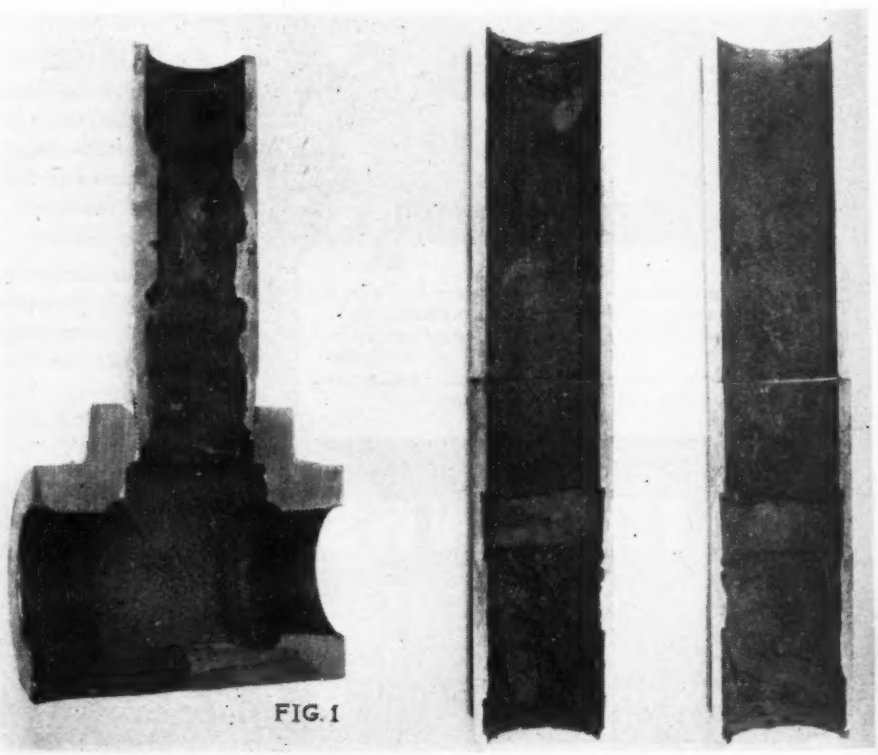

FIG. 1

*Presented before American Petroleum Institute, Southwestern District Division of Production, Houston, Texas, June 13-14, 1944.

[1]"Corrosion in Distillate Wells," by T. S. Bacon and E. A. Brown. *Oil & Gas Journal*—*41* No. 49, p. 91, April 15, 1943.

[2]"High Pressure Corrosion Controlled by Chemicals," by H. F. Simons, *Oil & Gas Journal*—*42* No. 17, p. 29, September 2, 1943.

[3]"The Need for a Method of Detecting Internal Corrosion," by T. W. McGuire, National Association of Corrosion Engineers, April, 1944.

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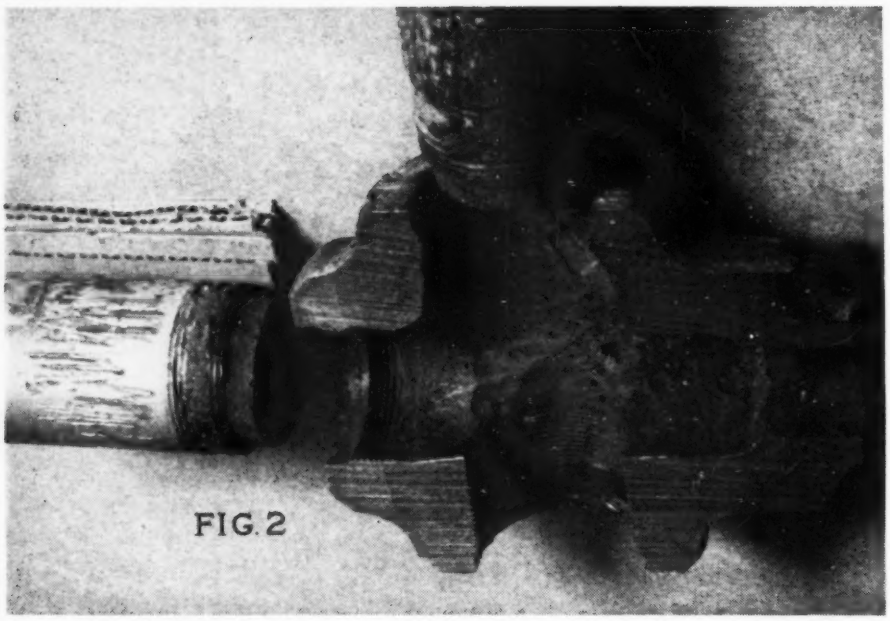

FIG. 2

ana fields and reported an expenditure of $71,500 in retubing one of these wells.[4] In addition, such wells in which tubing strings have failed are extremely difficult to kill, even though the surface fittings are intact, and any killing process may result in damage to the producing formation. The Lone Star Producing Company has had at least one case of tubing failure that has been ascribed to this form of corrosion.

In order to be on the safe side, it should be assumed that Christmas tree fittings have been appreciably affected by corrosion on any well in which the tubing has failed due to corrosion, and the killing job should, therefore, be handled with extreme caution. In fact, some experience indicates corrosion of the Christmas tree may occur without appreciable corrosion of the tubing. The Christmas tree on the Allyn No. 1 well at Opelika was found to be badly corroded about a year ago, and it was decided to inspect the tubing in this well to determine the degree of corrosion in the tubing. The corroded Christmas tree was replaced, and the well was killed and tubing pulled. Inspection of the tubing showed it to be in excellent condition, with only very slight corrosive attack on the bottoms of the tubing joints. The tubing was re-run, and the well brought back into production. The total cost of this inspection was $5735. On the other hand, in at least one well the tubing failed before the Christmas tree showed corrosive attack.

History. In view of the above considerations, operating personnel have shown an active interest in this problem and in its possible solution. However, it has been difficult to obtain a true picture of the magnitude of the problem, due to the number of fields involved, and due to the short periods of operation of many important distillate fields. The first step toward concerted action on the solution of this problem was taken at the meeting of the A.P.I. held in Chicago in November, 1943. The Southwestern District Topical Committee on Materials was assigned the study of this problem, and the preparation of a paper discussing the problem to be presented at the 1944 spring meeting of the Southwestern District.

Thirty-five representatives of interested companies met informally in Dallas in December, 1943, to discuss the magnitude of the problem and possible methods of procedure in attacking it. Evidences of this type of corrosion were reported as having been definitely observed in only 7 fields at this meeting. Close observations of 7 other fields, some of which had been producing for many years, showed this type of corrosion to be absent. The problem appeared to be of such importance to those attending this meeting that an independent committee was organized to investigate the problem, and to serve as a clearing-house for information regarding the problem, and ideas concerning its solution. There was no information available at this meeting regarding the action of the A.P.I. in this connection. This independent committee has recently disbanded, in view of the other committees on the same subject.

G. H. Calhoun, chairman of the Southwestern District Topical Committee on Materials of the A.P.I., appointed a special sub-committee on cor-

TABLE 1

Some high pressure fields in which corrosion occurs

No.	Field	County	State	Operator	Year field discovered	Evidences of corrosion
1	Bateman Lake	St. Mary	Louisiana	Texas	1937	Replacement of Christmas tree valves and nipples.
2	Brushy Creek	Lavaca	Texas	Shell	1941	Surface fittings attacked.
3	Buffalo	Leon	Texas	Lone Star Producing	1934	Corrosion of bottom hole chokes, requiring replacements.
4	Cayuga	Anderson	Texas	Seaboard	1934	Replacements of valves and Christmas trees.
5	Chapel Hill (Paluxy only)	Smith	Texas	Shell-Sun	1938	Choke beans cut out. Surface fittings attacked.
6	Cotton Valley	Webster	Louisiana	Cotton Valley	1922	Failure of two flow lines and five strings of tubing.
7	Delarge	Terrebonne	Louisiana	Union Producing	1938	Tubing failure.
8	Grapeland	Houston	Texas	Lone Star Producing	1936	Replacement of Christmas tree valves, fittings, and nipples.
9	Hester		Louisiana	Humble		Wellhead fittings corroded.
10	Katy	Waller	Texas	Stanolind	1935	No evidences of corrosion in 1942. Surface fittings found to be attacked in 1944. Many valves will require replacement.
11	Lake Mongoulois	St. Martin	Louisiana	Texas	1939	Replacement of Christmas tree valves and nipples.
12	LaPice	St. James	Louisiana	Shell	1939	Replacements of valves on Christmas tree.
13	Lisbon	Claiborne	Louisiana	Union Producing	1936	Tubing failures.
14	Long Lake	Anderson	Texas	Seaboard	1933	Replacements of valves and Christmas trees.
15	North Houston	Harris	Texas	Distillate Production Corp.	1938	Chemical analysis.*
16	North McFaddin	Victoria	Texas	Gulf	1937	Chemical analysis.*
17	Old Ocean	Brazoria	Texas	Abercrombie	1934	Tubing failures.
18	Opelika	Henderson	Texas	Lone Star Producing	1937	Replacements of Christmas tree valves and nipples.
19	Orchard	Fort Bend	Texas	Gulf	1936	Replacement of three flow lines after three years of service.
20	Red Fish Reef	Chambers	Texas	Humble	1940	Bottom hole chokes corroded.
21	Texana	Jackson	Texas	Gulf	1939	Chemical analysis.*
22	Lirette	Terrebonne	Louisiana	Humble	1937	Wellhead fittings corroded.
23	Willow Springs	Gregg	Texas	Lone Star Producing	1938	Replacements of Christmas tree valves and nipples. (Also probable cause of failure of one tubing string.)

Note: When produced water contains 100 p.p.m. of iron or more, fields are included in Table 1 on basis of "Chemical analysis." When produced water contains less than 100 p.p.m. of iron, fields are included in Table 2.

[4] "The Importance of Internal Corrosion of Tubing," by T. W. Johnson, National Association of Corrosion Engineers, April, 1944.

TOMORROW'S YARDSTICKS WILL BE LONGER

In American Industry today, far greater events are taking place "than meet the eye." For reasons of national security, many of these new developments in both products and processes are still in the "keep-it-under-your-hat" stage.

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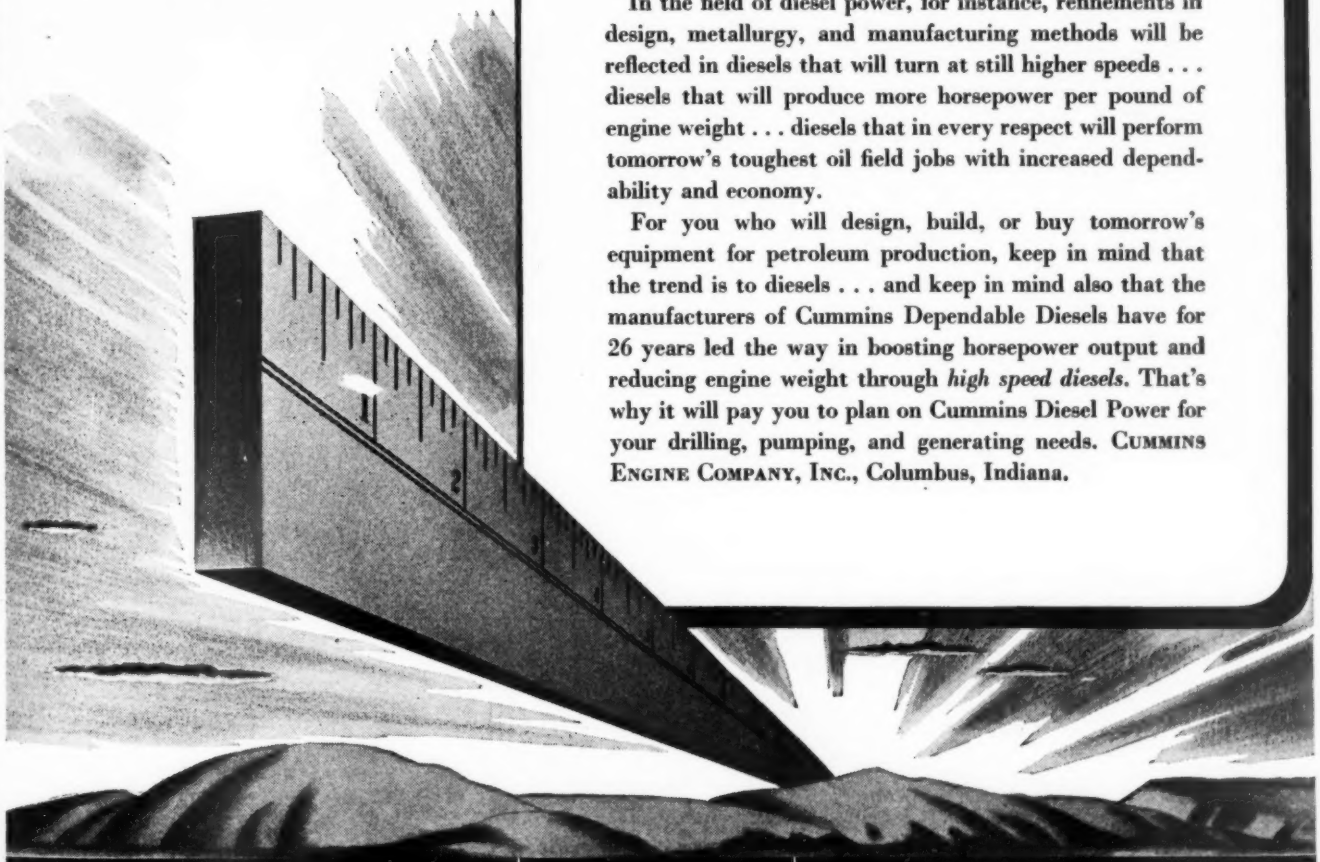
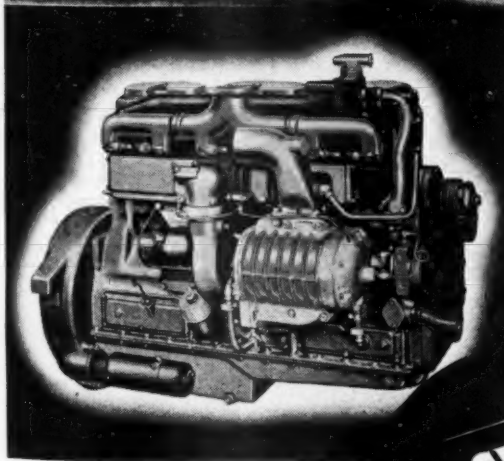
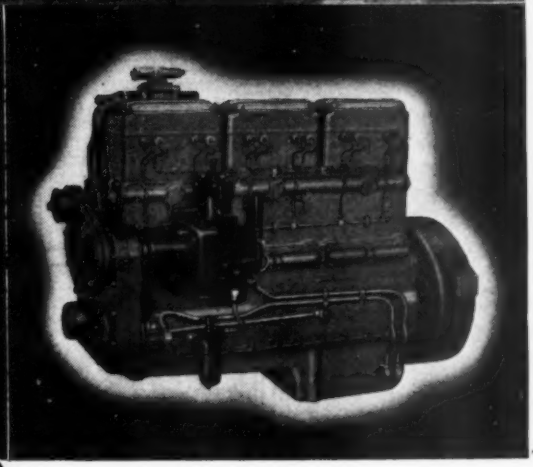




Left: Model HBIS (supercharged). 4⅞" bore x 6" stroke; 672 cu. in. displacement; 200 hp. at 1800 rpm.

Right: Model HBI-600. 4⅞" bore x 6" stroke; 672 cu. in. displacement; 150 hp. at 1800 rpm.



CUMMINS DIESELS

SINCE 1918...PIONEER OF PROFITABLE POWER THROUGH HIGH SPEED DIESELS

rosion of high pressure production equipment in March, 1944, "to determine causes of, and select remedies for, corrosion of high pressure production equipment, such as tubing, wellhead connections, flow lines, etc., particularly in high pressure condensate wells." The initial efforts of this sub-committee have been directed toward obtaining further information regarding the extent of the problem.

Tables 1, 2, and 3 are largely based on the results of a survey of operations of companies having representation on the above A.P.I. sub-committee. Table 1 lists fields in which corrosion has been evidenced either by failure of equipment, by corrosion severe enough to cause replacement of equipment, or by analyses of produced water samples for iron content.

It should be emphasized that this list of fields in which signs of corrosion have been observed does not include all fields in which signs of corrosion might be observable with careful examination. It has been the practice in the past to assume that sweet gas wells should be free of internal corrosion, and most operators have proceeded on that theory until the past few months. Therefore, many fields have not been examined carefully for signs of this corrosion, and the only possible way in which this corrosion could be evidenced in these fields would be by failure of equipment. Even with severe corrosive attack, failure of equipment will result only after prolonged periods of exposure, so there is reason to believe that additional fields will show corrosion in the future. Further, the data in Table 1 has been obtained from a few companies only, and no attempt has been made to survey all operators in compiling these data.

In spite of the lack of complete data regarding the occurrence of this corrosion, the frequency of its occurrence as indicated in Table 1 is sufficient to indicate that it definitely presents a real operating problem to the industry.

Table 2 lists fields that have been examined for this type of corrosion, and have been found to be free of corrosion. It is interesting to note that the Rodessa and Pettit formations in the Chapel Hill, Texas, field are non-corrosive while the Paluxy formation is definitely corrosive. Here again, this list of non-corroded fields is incomplete. It is also interesting to note that this type of corrosion has not been observed in the South Gulf Coast area.

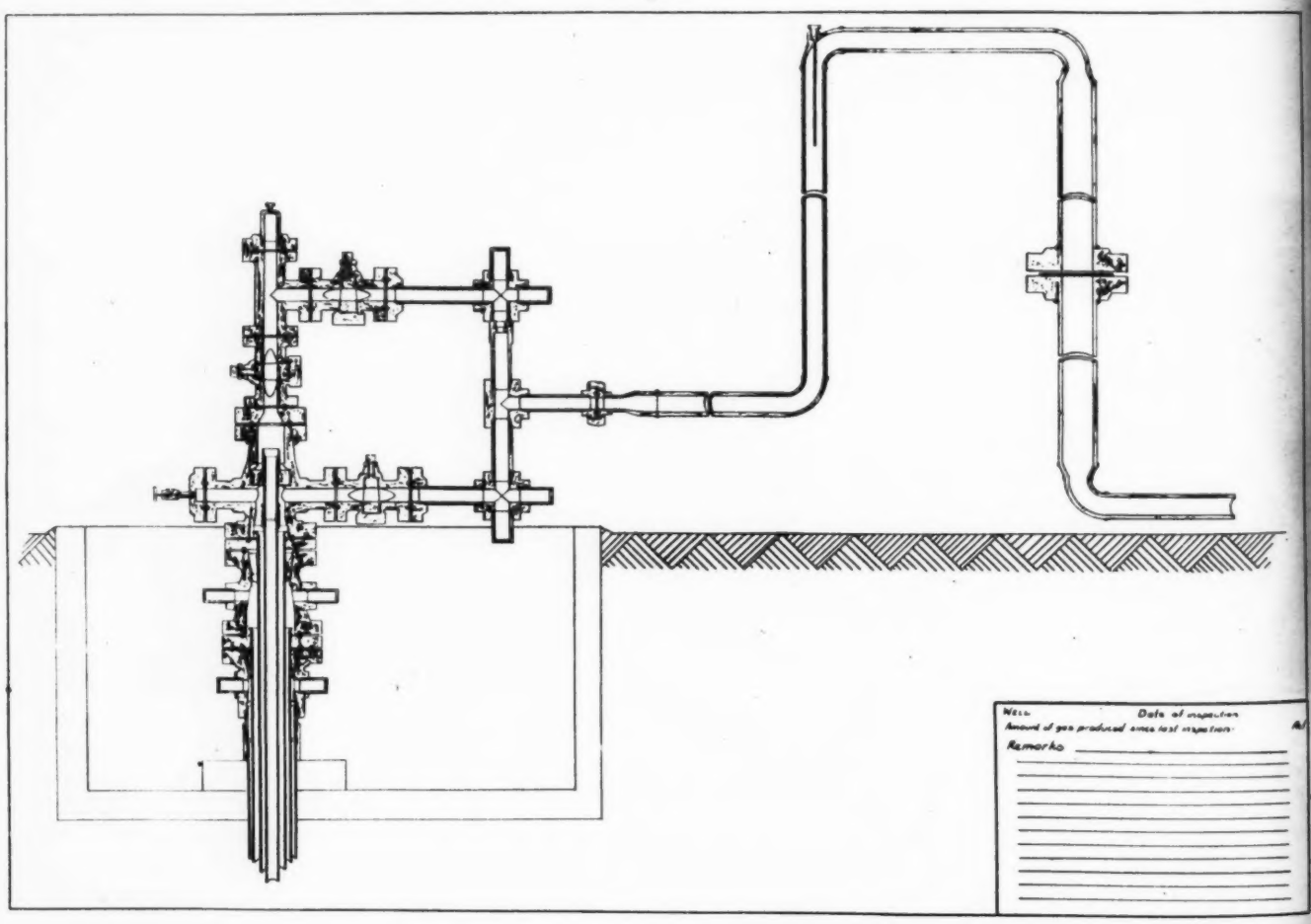
Table 3 is of interest in indicating the frequency of corrosion as shown by the reporting companies. Here again, the data are incomplete, but the possibility of finding corrosive conditions in a new field is emphasized. The corrosive conditions have been shown to occur with such frequency that the possibilities of finding appreciable corrosion in any high pressure field cannot be overlooked with safety.

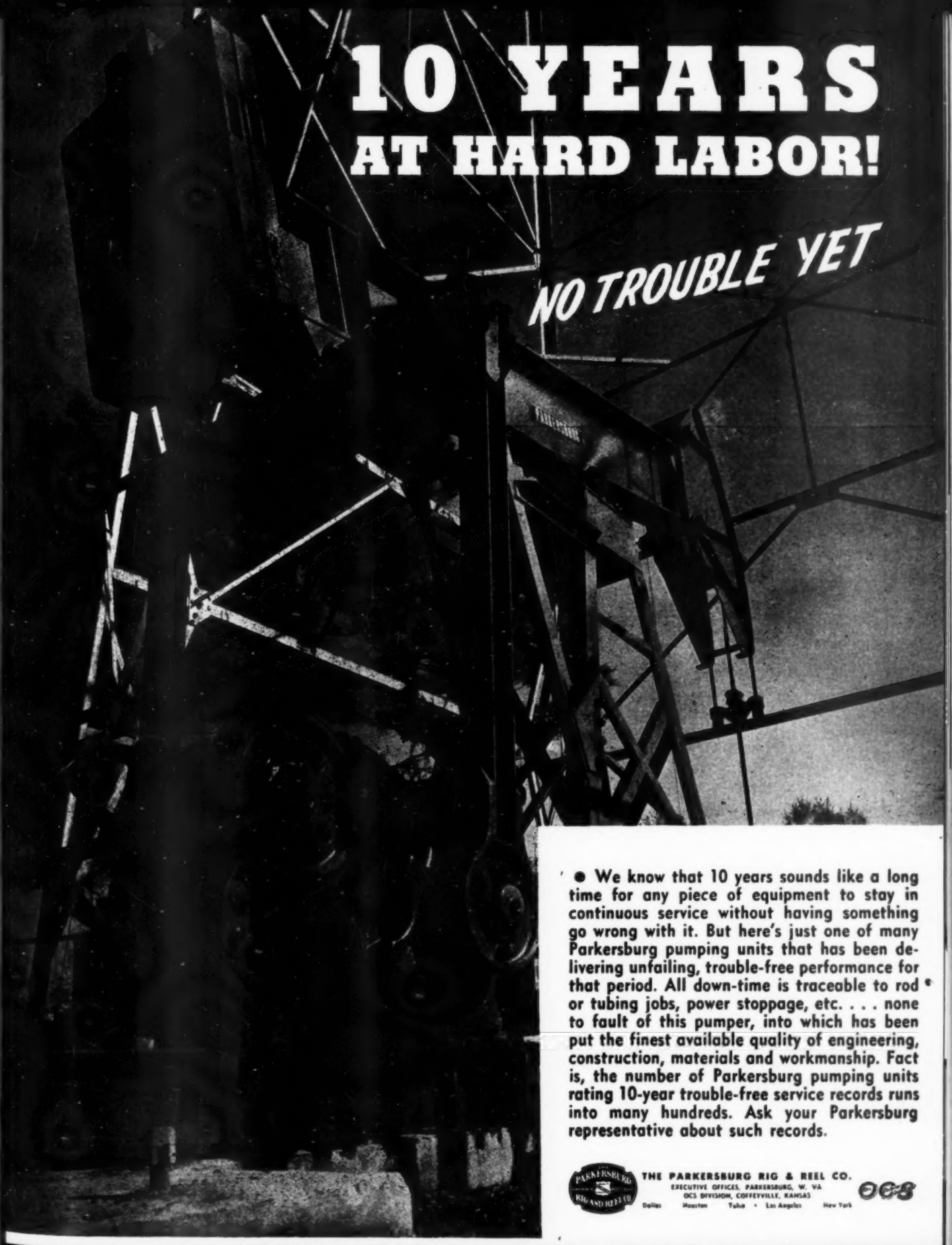
Corrosion tests. The above discussion indicates the need for some sure method of detecting the presence of this corrosion so that remedial measures may be taken before corrosion has proceeded far enough to be dangerous. Accurate tubing calipers that could be run under pressure would be of extreme value in this connection, although, unfortunately, no such instrument is commercially available to the knowledge of the writer. [5] Visual inspection of surface fittings seems to be the most practical way at present to determine the degree of corrosion in these fittings. Chemical tests for dissolved iron in water produced by each well are at least indicative of the likelihood of the presence or absence of serious corrosion.[6] In the writer's experience, corrosion

[5] "Proposed Method of Detecting Internal Corrosion," by T. B. McDonald, National Association of Corrosion Engineers, April, 1944.

[6] "Estimates of Corrosion Rates by Chemical Analysis," by E. A. Brown, National Associaion of Corrosion Engineers, April, 1944.

Fig. 3





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will be almost negligible in wells showing less than 50 p.p.m. of iron in the produced water. Wells showing iron concentrations of from 75 to 100 p.p.m. in the produced water should be watched for other signs of corrosion and wells showing iron contents in excess of 300 p.p.m. should be carefully inspected every three months.

Properly supervised chemical tests for iron in produced water samples are believed to be available in safeguarding operations of these high pressure properties. Water samples should be obtained with care and at frequent intervals and, in the writer's opinion, should be acidified with nitric acid as soon as taken to insure that all iron remains in solution. If it is desired to record the pH value of the produced water, this may be done before addition of the nitric acid by the use of a field kit for the determination of pH. Iron may be lost from solution in these samples on standing even when reasonable precautions have been taken to prevent access of air to the samples, particularly if the samples are of high iron content. It is the present practice of the Lone Star Producing Company to install necessary sample taps wherever it is felt that additional chemical analyses are desirable. By determining dilution caused by condensation of additional water vapor from the gas on the basis of the chloride content of the water samples from any one well, it is possible to correlate iron contents of the various samples and, therefore, determine the amount of iron dissolved from the system between each pair of sampling points, if the volume of water produced at any sampling point is known.

The question of concentration of iron in the liquid connate water entering the produced stream from the formation is of importance in this connection. The iron/chloride ratios of ordinary connate waters may be of value in estimating the effect of dissolved iron in the produced connate water on the iron content of any water sample obtained at the surface. The Lone Star Producing Company's experience indicates that iron dissolved in the connate water amounts to less than 5 p.p.m in the average surface sample.

Chemical tests, coupled with a knowledge of the amount of liquid water in the produced stream at the point of sampling, are of value in estimating the total weight of iron removed from the pipe line system by corrosion. However, these tests do not indicate whether this weight of iron has been removed uniformly from the total exposed metal surfaces to give very slight penetration of the pipe walls, or whether the corrosive attack has been highly localized, resulting in serious weakening of a part of the metal structure. Therefore, any chemical tests showing appreciable iron concentrations should be supplemented by other methods for determining the location of the corroded surfaces, and for determining the depth of penetration of the metal walls.

It may be assumed that gas in the reservoir is saturated with water vapor under the existing conditions of temperature and pressure. Some of this water vapor will be condensed to liquid water as the gas is cooled during production. The actual volume of water condensed will depend on reservoir conditions and on flow line conditions, but will be of the order of magnitude of 1 bbl. per million cubic feet of gas. If it is assumed that water samples at the wellhead show a dissolved iron content of 100 p.p.m., the production of each billion cubic feet of gas would result in the production of 35 lbs. of iron in solution in the water associated with this gas. If this iron is removed uniformly from the interior surface of 10,000 ft. of tubing, penetration of the tubing will be negligible. However, if all of this corrosion is concentrated in the top joint of tubing, this joint will be seriously weakened.

Water samples may readily be obtained from the inlet separator at any recycling plant, and the amount of iron in these samples can be determined at small cost. The total weight of iron per day removed from the system by the water leaving the inlet separator can then be calculated if the volume of water drained from the separator is known. If this weight if iron is negligible, absence of corrosive attack of the production system is indicated. But, if this weight of iron is appreciable, the likelihood of corrosive attack of some part of the production system is indicated.

Occasionally, samples of the produced water will contain insoluble iron compounds. Such cases that have been reported are very few, and are difficult of explanation. The presence of insoluble iron compounds in the produced water under flowing conditions will, of course, interfere with any conclusions based on analyses of the water samples, as the iron precipitates will vary in concentration in the water sample, depending on the sampling system. If iron sludge or deposits of insoluble iron compounds are found at any place in the system, it is believed likely that corrosion will be found at some place upstream from the sampling point.

Present remedial practices. The industry has not yet standardized on any remedy for this type of corrosion. Many operators are presently relying on visual inspections of all equipment that is suspected of attack by this corrosion to reveal any dangerous condition. Any equipment that is found to be seriously weakened in the course of these inspections is replaced by new equipment of the same type. Other operators are specifying that all master valves in high pressure service be lined with corrosion-resisting alloys. Other operators are injecting chemicals into the flow system at some point in an effort to eliminate corrosion downstream from the point of injection.

The Lone Star Producing Company

TABLE 2

Some high pressure fields in which corrosion has not been observed

No.	Field	County	State	Operator	Year field discovered	Oil or gas	Operating pressure, lb. per sq. in.
1	Agua Dulce	Nueces	Texas	Chicago Corp.	1928	Gas	1500-2500
2	Belle Isle	St. Mary	Louisiana	Sun	1941	Gas	3100
3	Caplen	Galveston	Texas	Sun	1940	Gas	2700
4	Chacahoule	Lafourche	Louisiana	Sun	1938	Gas	3100
5	Chapel Hill (Rodessa & Pettit)	Smith	Texas	Sun	1938	Gas	....
6	Chocolate Bayou	Brazoria	Texas	Stanolind	1939	Gas	4200
7	Fig Ridge	Chambers	Texas	Sun	1940	Gas	3000
8	Flour Bluff	Nueces	Texas	Humble	1936	Gas	....
9	Government Wells	Duval	Texas	Humble	1928	Gas	....
10	King Ranch	....	Texas	Humble	....	Gas	....
11	LaBelle	Jefferson	Texas	Sun	1937	Gas	3170
12	LaRosa	Refugio	Texas	Stanolind	1938	Gas	2300
13	Lewisburg	Acadia	Louisiana	Stanolind	1941	Gas	3000
14	Lovells Lake	Jefferson	Texas	Humble	1938	Gas	....
15	Neale	Beauregard	Louisiana	Sun	1940	Oil	2700
16	Old Ocean (Campbell Sand)	Brazoria	Texas	Sun	1934	Oil	3450
17	North Bay City	Matagorda	Texas	Sun	1942	Gas	1850
18	North Crowley	Acadia	Louisiana	Humble	1937	Gas	....
19	North Elton	Allen	Louisiana	Stanolind	1939	Gas	2800
20	North Markham	Matagorda	Texas	Sun	1938	Gas	1100 (Bottom hole regulators)
21	North Winnie	Chambers	Texas	Sun	1943	Oil	2200
22	Pledger	Brazoria	Texas	Humble	1932	Gas	....
23	Riverside	Nueces	Texas	Stanolind	1939	Gas	3250
24	Seabreeze	Chambers	Texas	Sun	1936	Gas	2200
25	Shield	Nueces	Texas	Stanolind	1940	Gas	1650
26	Shuteston	St. Landry	Louisiana	Sun	1943	Oil	2200
27	South Elton	Jefferson Davis	Louisiana	Stanolind	1937	Gas	2850
28	South Jennings	Jefferson Davis	Louisiana	Stanolind	1936	Gas	3150
29	Stratton	Nueces	Texas	Chicago Corp.	1931	Gas	1500-2500
30	Welch	Jefferson Davis	Louisiana	Stanolind	1902	Gas	3400
31	Willow Slough	Chambers	Texas	Sun	1937	Gas	2775

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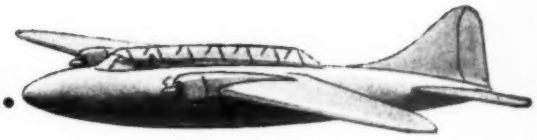

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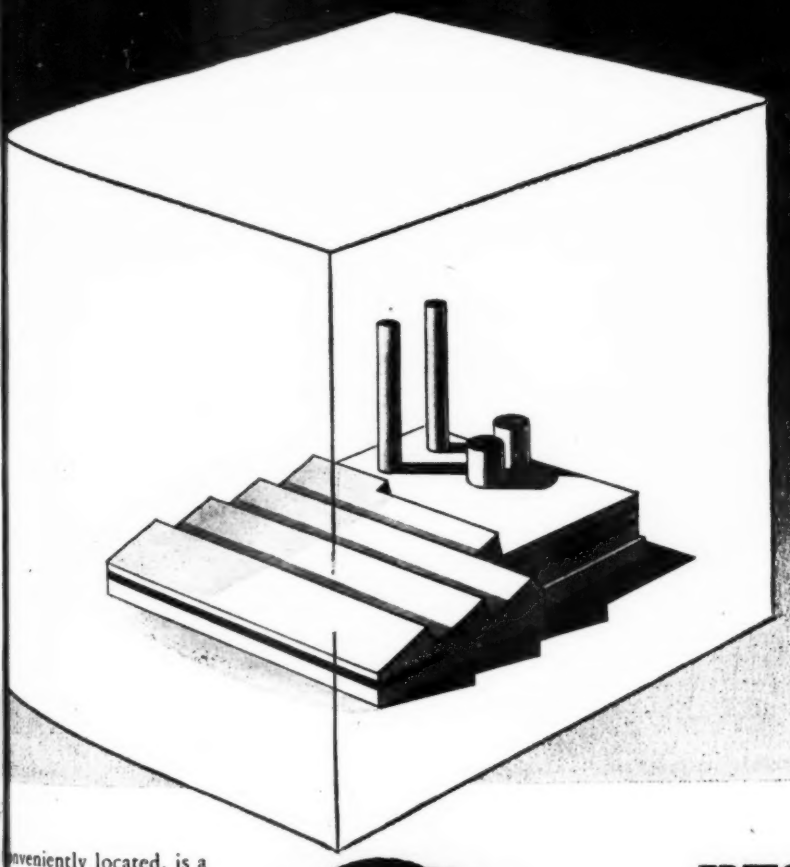

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DEHYDRATING **DESALTING**

has practiced the injection of chemicals into wells in the Opelika field for more than a year. The initial treatment tried in the Opelika field involved the injection of soda ash solution into the well casing at a rate of 1.0 lb. of soda ash per million cubic feet of gas produced from the well. As these wells are produced through tubing only, the soda ash solution injected into the casing trickled down the casing to the producing formation and left the well through the produced gas stream in the tubing. This method of chemical treatment reduced the rate of corrosion very materially as indicated by chemical tests and also by visual examination of surface fittings. However, a calcium carbonate scale was deposited in the tubing perforation or in the tubing itself that eventually built up to sufficient thickness to act as an effective bottom hole choke. This scale was easily removed by treatment with 4 bbl. of acid per well but reformed at such a rate that acidization was required again in approximately thirty days. In an attempt to reduce the rate of deposition of this calcium scale, the concentration of soda ash was reduced to about 0.10 lb. per million cubic feet of gas produced. An equal amount of sodium hexametaphosphate was added to the solution in an attempt to avoid calcium deposition and also possibly to serve as an inhibitor. An organic chromium compound was also added to the treating solution in the amount of approximately 0.05 lb. per million cubic feet of gas produced to act as an additional corrosion inhibitor. This solution did not appear to cause deposition of sufficient calcium carbonate scale to require frequent acidization. However, this solution was far less effective in reducing the rate of corrosion than was the more concentrated soda ash solution used originally. The organic chromium compound has recently been replaced in this solution by sodium dichromate with 0.20 lb. of sodium dichromate used per million cubic feet of gas produced. The sodium dichromate appears to be much more effective in this service than the organic chromium compound first used.

The Lone Star Producing Company has used various other chemicals and inhibitors for short lengths of time on various wells. Aqueous ammonia was injected into one well and reduced corrosion satisfactorily but caused calcium carbonate deposition. An organic corrosion inhibitor was injected into another well for a period of several months with some apparent reduction in the rate of corrosion of the surface fittings. However, traces of sludge in this inhibitor interfered seriously with operation of the pump used for injection, so further work on this inhibitor was abandoned. Sodium silicate was injected into one wellhead at a rate of 0.8 lb. of silicate per million cubic feet of gas. A heavy deposit of silica was found in the wellhead at the point of injection after three weeks of operation, so use of this chemical was abandoned even though chemical tests indicated excellent corrosion control.

There are a wide variety of inhibitors that might be useful in this service. Additional field tests are planned on some of these inhibitors.

Protective coatings have not been tried extensively in field service. The Lone Star Producing Company recently had a section of a Christmas tree coated internally with a synthetic plastic lining that was baked on. This coating was inspected after 6 weeks' service and appeared to be in perfect condition.

Protective films are subject to failure for one reason or another and it is possible that corrosive attack may be concentrated at the points of failure. Satisfactory alloys are not subject to this objection. Therefore, a study of the use of low-cost alloys is indicated. This study would necessarily be slow as possible alloys should be exposed to actual operating conditions for a sufficient length of time to determine whether or not they are slowly corroded in service. Such alloys are extremely difficult to obtain under existing conditions and service tests of at least 12 months would be required to indicate the relative values of any alloys that might prove satisfactory. In this connection, a 2-in. flanged tee that was recently removed from a well in the Grapeland, Texas, field was found to be nearly free of corrosion, whereas the two valves bolted directly to the tee were badly corroded. Investigation disclosed that the metal in this particular tee contained approximately 0.5 per cent chromium and 1.5 per cent nickel. If an inexpensive alloy generally resistant to this type of corrosion could be found, its wide use would be indicated.

Any conclusions based on observations of the behavior of alloys are necessarily subject to question if the exposed surface of the alloy is small, and if the alloy is in electrical contact with ordinary steel pipe or fittings, due to the likelihood of setting up galvanic cells under these conditions in which the alloy could become cathodic, and might be protected at the expense of the adjacent steel equipment. Observations of gate valves have shown that brass guides in these valves, and hard-surfaced disks in these valves, have not been corroded whereas the steel parts of these valves have been badly corroded. Stainless steel sampling tubes have been unaffected by this corrosion, whereas steel sampling tubes have failed after 2 years' service. Orifice plates of stainless steel have remained free of any signs of corrosion, while the steel meter runs have been badly corroded.

The successful injection of chemicals into the flow stream below the surface fittings is almost impossible for mechanical reasons in a dually completed well or in a well in which the tubing is packed off from the casing. In such wells the use of satisfactory alloys or of satisfactory protective films on subsurface equipment appears to be the only practicable means of combating internal corrosion due to the mechanical difficulties of introducing any possible method of chemical or electrical protection into the flowing stream below the surface fittings when the well is in operation. Continuous chemical treatment of any well involves an appreciable expenditure for operation of the injecting equipment, and requires constant and careful supervision, again emphasizing the desirability of alloys.

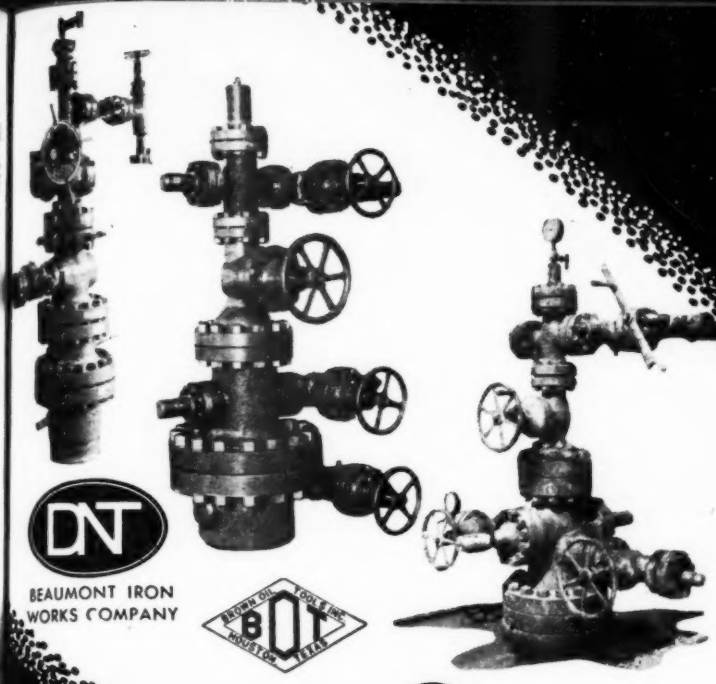
Future work. An intelligent attack on this problem would require determination of the causes of this corrosion. These causes are not definitely known at present. Complete information regarding the chemical nature of the produced fluids and the geologic and physical conditions of production should be of material assistance in attempting to determine causes of this corrosion. To assist in compilation of this information, a comprehensive questionnaire is included as an appendix to this paper. If sufficient numbers of these question-

TABLE 3

Corrosion experiences of reporting companies

Company	Total fields reported operated at pressures above 1500-lb. per sq. in.	Number of fields not corroded	Number of fields showing corrosion	Per cent of fields inspected showing corrosion
A	4	0	4	100
B	9	3	3	50
C	3	0	2	100
D	4	1*	3†	75
E	10	6	4	40
F	14	13	1	7
G	10	9	1	10
	Total.....	32	18	36

*Based on chemical analysis only.
†Two fields classed as corrosive on basis of chemical analysis only.



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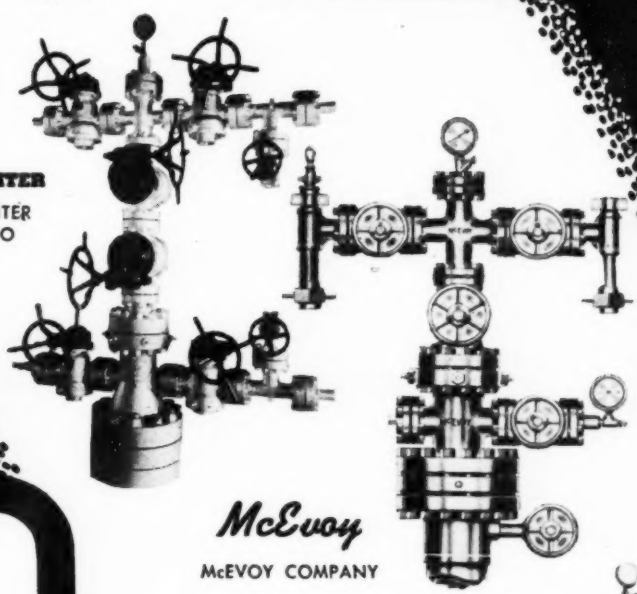

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naires could be filled out showing conditions in both corroded and non-corroded wells, it appears likely that an analysis of the then available data should assist in indicating possible causes of this corrosion. It is, of course, obvious that determination of the causes of this corrosion would be of tremendous value to the operator who drills in a new high pressure field and must specify the type of equipment to be installed in the field. A knowledge of the cause or causes of corrosion could also be of material benefit in planning ways and means of eliminating or minimizing this corrosion. The questionnaire has been included in this paper to direct attention to many of the details that might have some bearing on the presently unknown cause or causes of this corrosion. Available data showing the approximate ranges of various conditions reported to date as existing in corroded wells are not complete. However, some approximate values of these conditions have also been included in the appendix to show at least some conditions under which this particular type of corrosion has occurred.

Many companies are actively investigating probable causes of this corrosion at present and full interchange of ideas and data developed by this work appears to be desirable. It is the function of the A.P.I. Sub-Committee on High-Pressure Corrosion to assist in this interchange at present. Two papers discussing theories of causes of this corrosion were presented at the annual convention of the National Association of Corrosion Engineers held in Houston, Texas, April 10-12, 1944.[7, 8] Both authors ascribed the corrosive attack primarily to the presence of carbon dioxide in the produced gas, but one author [8] indicated that, in his opinion, other conditions, such as rate of flow of gas, and fluid film behavior at high flow rates, would possibly affect the rate of corrosive attack. Further development of these theories is desirable, but any satisfactory theory must explain all of the anomalies of behavior that have been indicated above, and must stand the test of explaining field observations.

The Natural Gasoline Association of America has recently appointed a committee to study this corrosion problem. This committee has concluded that the problem is of such magnitude that the industry should superimpose a centralized research program on the various individual research efforts that are under way at present. It should be emphasized in this connection that all existing work by individual companies and by various committees of the petroleum industry should be continued to the utmost. However, the detached viewpoint of a commercial research institute should be of value in considering this problem. The Natural Gasoline Association of America has retained the Battelle Memorial Institute, of Columbus, Ohio, to initiate this research work. The Natural Gasoline Association of America is also considering the retention of other organizations or individuals to assist in this research program. The work will be financed by direct contributions from interested companies. Such a program should permit a more rapid solution of the problem than any suggested alternative procedure, and speed in the solution of this problem is extremely desirable. Full cooperation of the industry with the research groups selected will, of course, be essential as the research groups must have full access to all facts regarding field operations to work most efficiently. Also, field samples will be required, and many field tests of processes and equipment will probably be required before a final answer is reached. The difficulties to be encountered in this proposed program of research are still largely unknown, and it is impossible to estimate the time required for satisfactory completion of this work at present. The problem does appear presently to be of such magnitude that its solution will require several years, and the program of attack should be based on that assumption. But, until this problem is satisfactorily solved, this new form of high pressure corrosion will continue to offer a serious hazard to life and property, and will be of direct concern to every operator of a high pressure gas well.

Conclusions. The problem of corrosion of high pressure production equipment is a very real problem insofar as the petroleum industry is concerned.

Information regarding the exact causes of this corrosion is not presently available.

No generally satisfactory methods of combating this corrosion have been proved.

The problem can best be attacked by the cooperative efforts of the petroleum industry.

Acknowledgement. Acknowledgement is made to the members of the A.P.I. Southwestern District Topical Committee on Materials for their valuable cooperation in furnishing data used in the preparation of this paper. The kindness of L. T. Potter and E. A. Brown, of the Lone Star Producing Company, in reviewing the paper and offering constructive suggestions is also acknowledged.

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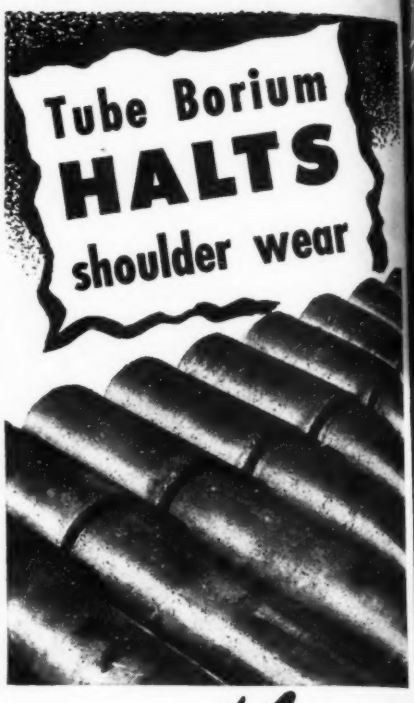
[7] "Some Studies of Water Produced by High-Pressure Wells," by W. F. Rogers, National Association of Corrosion Engineers, April, 1944.

[8] "A Study of Corrosion in Gas and Condensate Wells in the Katy Field, Texas," by F. W. Jessen, National Association of Corrosion Engineers, April, 1944. Also published in *Oil & Gas Journal*—42 No. 52, p. 53, May 4, 1944.



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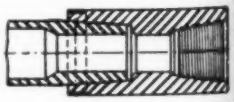

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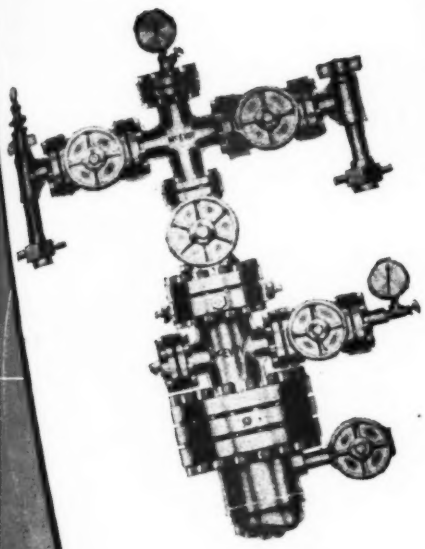

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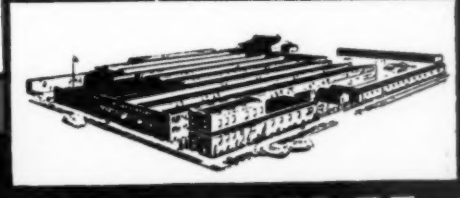

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A New Application of Water Injection for Maintaining Reservoir Pressure and Increasing Natural Water Drive*

By WILLIAM L. HORNER and D. R. SNOW
Barnsdall Oil Company

INTRODUCTION. Recognition by the industry of the advantages of water drive at maximum reservoir pressure has resulted from considerable research and many years of practical study of reservoir behavior. It has been advocated that production under effective water drive be accepted as the engineering and conservation standard to be achieved and, further, that the rate of production for each pool should be restricted so as to permit the water drive to be effective.[1] There is little doubt that the majority of oil pools have had some degree of water drive. In the Bartlesville sand in northeastern Oklahoma it was found that pools having the best water drives were located nearest the outcrop from which a certain amount of recharging water could have entered and in areas known to be connected effectively with large unbroken volumes of water-bearing reservoir.[2] Many pools depend upon the expansion of water in major sand bodies to supply influx for natural water drive. Examination of geological conditions shows that water influx often is seriously limited, and explains why some pools have had only partial water drives.[3] In the Oklahoma City Wilcox pool it is reported[4] that 509,000,000 bbl. of pore space, representing only 41.7 per cent of the reservoir, was permeated by water by July 1, 1940, and since that time water influx has continued at a greatly reduced rate. Less than 20,000 bbl. of water per day has been produced since April, 1938, with no rise in water level. Results of studies of reservoir behavior and examination of production records in many fields have shown that natural water drive is usually unable to maintain sufficiently rapid influx at a rate for maximum economic benefit. Restriction of production rates often will be found to be acceptable conservation practice, although such procedure does not increase the volume of water available. Inasmuch as the question is that of "degree" of water drive, it should be well to search for more positive means of its control. Injection of extraneous water may be regarded as a direct approach to the problem of improving and sustaining natural water influx. However, it is believed that no quantitative data have been accumulated and presented heretofore which demonstrate the feasibility of the method.

In the Midway field, Lafayette County, Arkansas, fresh water has been injected since April 19, 1943, into the Smackover formation underlying and at the edge of the oil reservoir. The essential factual data, together with the results of material-balance calculations and pressure predictions, are presented.

Reservoir characteristics. The field was discovered by Barnsdall Oil Company's No. 1 Bond, which was completed, January 1, 1942, in the Reynolds "oolitic" zone of the Smackover limestone.[5] As of October 1, 1943, there were 39 producing wells in the field—30 flowing and 9 pumping. The producing area has been found under sections 9, 10, 11, 12, 13, and 14, of township 15 south, range 24 west, and section 18, township 15 south, range 23 west, Lafayette County, Arkansas (Fig. 1). The field lies to the north of a major faulted zone regarded as being related to the Balcones fault system of Texas, and which previously had marked the northern limit of production from the Smackover limestone. A productive area of approximately 1700 acres is estimated (Fig. 2).

Study of the structural map and cross-section (Fig. 3) shows the reservoir in the crest of a steeply folded elongated anticline. There is no gas cap. The oil column reaches a maximum thickness of approximately 200 ft., which is in an area around the discovery well. The water-oil contact is apparently not a definite plane; but a practical and arbitrary level has been chosen, 6225 ft. below sea level, on the basis of information from production tests, mud-analysis logs, electrical logs and cores. The volume of Smackover formation below the top of porosity and above 6225 ft. below sea level has been calculated to be approximately 126,000 acre-feet. Study of numerous electrical logs, core analyses, and a bottom-hole-sample analysis shows this volume to contain 150,00,000 bbl. of oil as would be measured under stock-tank conditions. This amount of oil is the amount in place—a portion of which is recoverable—the amount of recovery largely depending on the efficiency of expulsion.

Non-uniformity of the formation is disclosed by data collected on many of the wells drilled. Coregraphs and electrical logs (Fig. 4), as well as drilling-rate curves, show that a large proportion of the reservoir is of low permeability. The problem of producing maximum quantities of oil from individual wells with minimum quantities of water has been found to affect directly the yield obtainable. When limited by a given completion technique, more oil can be recovered if sufficient water is available to continue operations so that higher percentages of water can be produced; thereby flushing action can be made more complete in the less-permeable parts.

Pressure history. The initial reservoir pressure was measured to be 2920 lb. per sq. in. at 6050 ft. below sea level. Bubble point of the reservoir oil is 2528 lb. per sq. in. abs., at a reservoir temperature of 182° F. Rapid decline in bottom-hole pressure, which characterized reservoir behavior, was observed following discovery of pressure falling to 2665 lb. per sq. in. by May 1, 1943—a decline in excess of ½ lb. per sq. in. per day. During this period frequent and accurate measurements of reservoir pressure were obtained by the Barnsdall Oil Company and the Arkansas Oil and Gas Commission, and at the same time accurate measurements (Fig. 5) were recorded as to the amounts of oil, gas, and water produced. Physical measurements on a reservoir sample of crude provided information as to the expansibility of the reservoir oil with changes in pressure, and also determined the formation volume factor and shrinkage used for correcting stock-tank oil volume to barrels of reservoir oil.

Material balance. Based on these measurements, material-balance calculations were made (Fig. 6) for several successive periods during withdrawal of more than two million barrels of oil. The principle of these calculations[6] used in this connection to determine the amount of water drive can be stated as follows:

> **Total withdrawals, barrels of reservoir oil = expansion of reservoir + water influx.**

The total amount of water influx for each pressure survey was calculated by that equation, the remaining factors having been determined by the physical measurements. Based on the pressure surveys ending February 16, 1943, an average daily influx of 5290 bbl. per day was calculated for the previous 55-day period. This figure was compared to 6660 bbl., the average daily withdrawal of reservoir fluids for the same period. This suggested the probability of retarding the rate of pressure decline by augmenting the natural drive some 1400 bbl. per day by injecting a larger

*Presented before American Petroleum Institute Division of Production, Chicago, Illinois, November 11, 1943.

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quantity of fresh water. It was obvious that, should this step succeed, reservoir pressures could be increased by increasing injection rates. The literature shows[7] that successive reductions in withdrawal rates failed to halt but temporarily the decline in reservoir pressures in Buckner, a similar pool, near Midway. Because of these reasons, and because an adequate low-cost water supply was available at Midway, the economic possibilities of experimental water injection were clear.

Injection well. With the permission of the Arkansas Oil and Gas Commission, Barnsdall's No. 2 M.F. Creek, a dry hole located in the southeast quarter of section 10, township 15 south, range 24 west, was converted into an input well. This well had encountered the top of Smackover porosity at 6240 ft. below sea level. To convert this well for input purposes, 5½-in. O.D. casing was set at 6343 ft. below sea level in the 9⅞-in. diam. hole which had been deepened to 6490 ft. below sea level. The last 20 ft. drilled were dense crystalline limestone, without permeability. Of the section exposed, approximately 100 ft. were indicated to be permeable according to an interpretation of the electrical log and cuttings. The top of the zone exposed was 118 ft. below the water-oil contact for the field, and 103 ft. below the top of the formation (Fig. 3). The open hole was underreamed to gage, the surface of the formation being scraped with the underreamer while fresh water was used to circulate out the cuttings. The face of the formation was cleaned with a light acid wash, and a short injection test was made to determine input capacity—which was found to be approximately 3 bbl. per day per lb. per sq. in, of pressure. After acidizing with 7000 gal., another test showed 7.6 bbl. per day per lb. per sq. in. of pressure. From a shallow water-supply well operated by gas lift, water was supplied to the well through a 4-in. by 10-in. power pump, and injection was commenced on April 19, 1943. Four days later the injection capacity had fallen to 4 bbl. per day per lb. per sq. in. of pressure. Since that date the input capacity has remained substantially the same, no decline having been noted in the 4-month period ending September 23, 1943—at which time a total volume of 350,000 bbl. had been injected, an average rate of 2200 bbl. per day against a pressure of approximately 620 lb. per sq. in. The fact

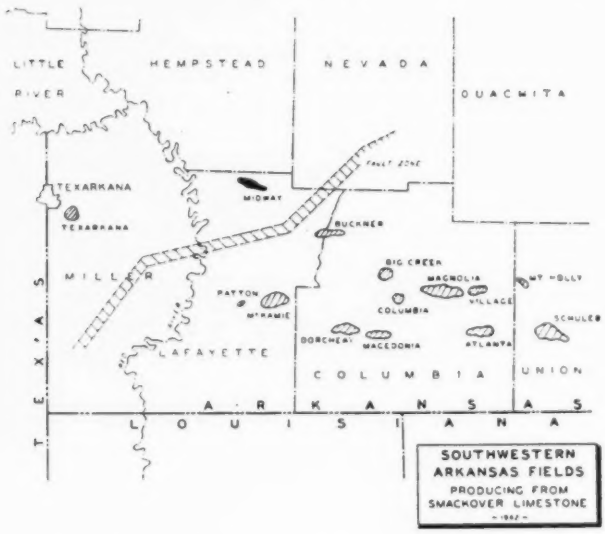


Fig. 1. Location of Midway field, southwestern Arkansas

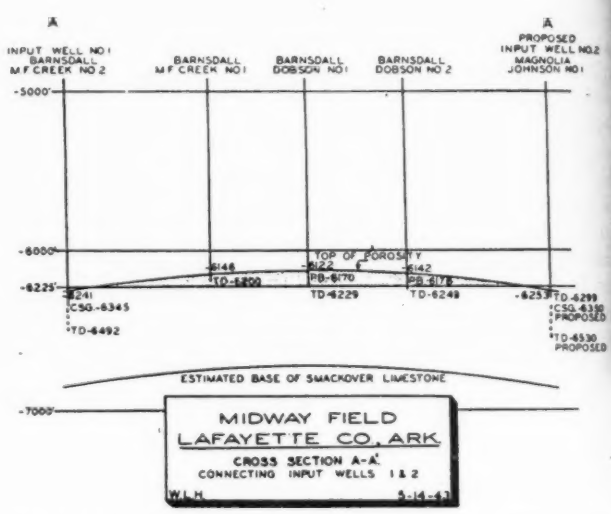
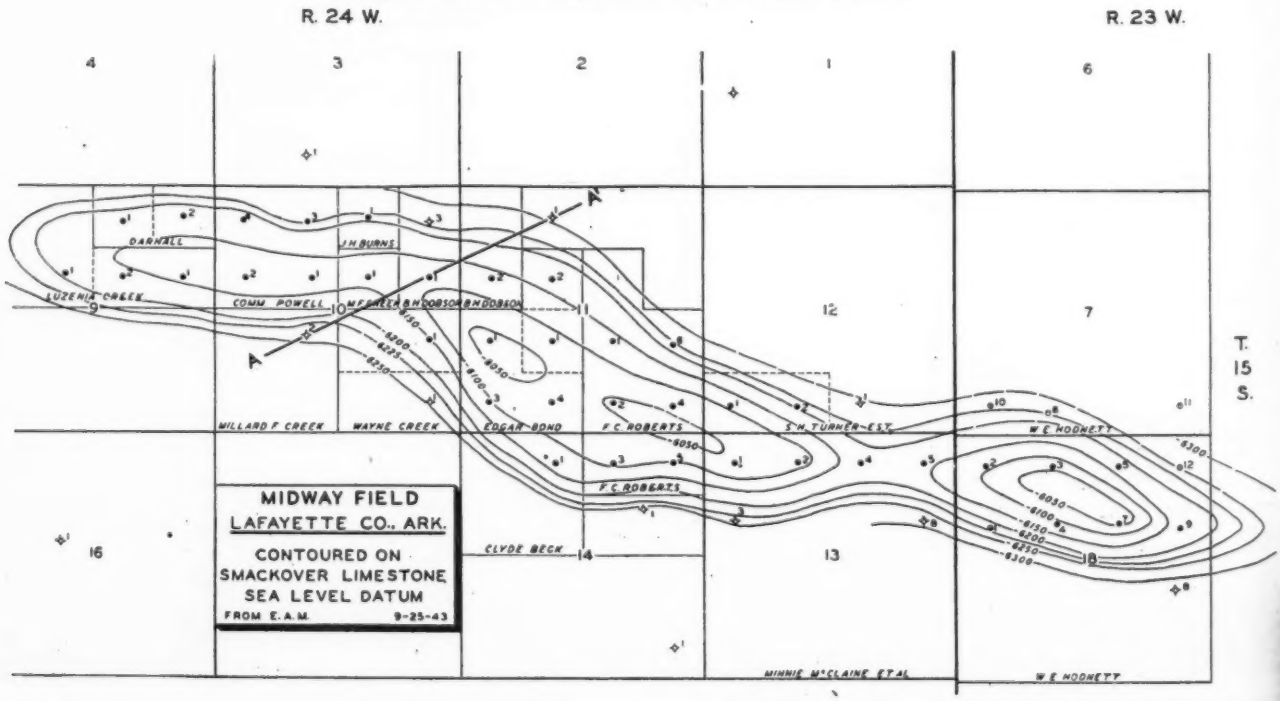


Fig. 3. Cross-section connecting input wells Nos. 1 and 2

Fig. 2. Structure map, contoured on top of porosity



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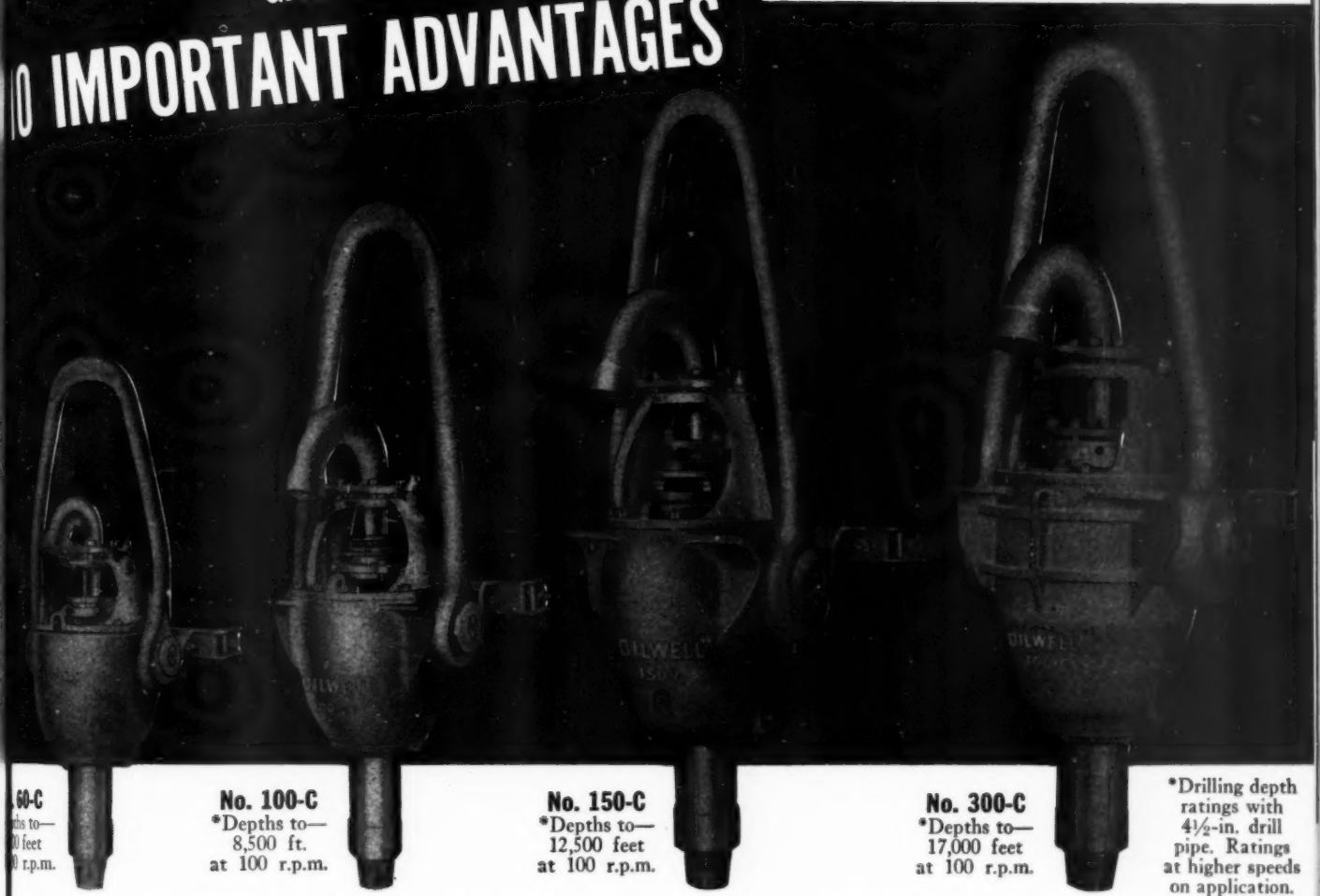

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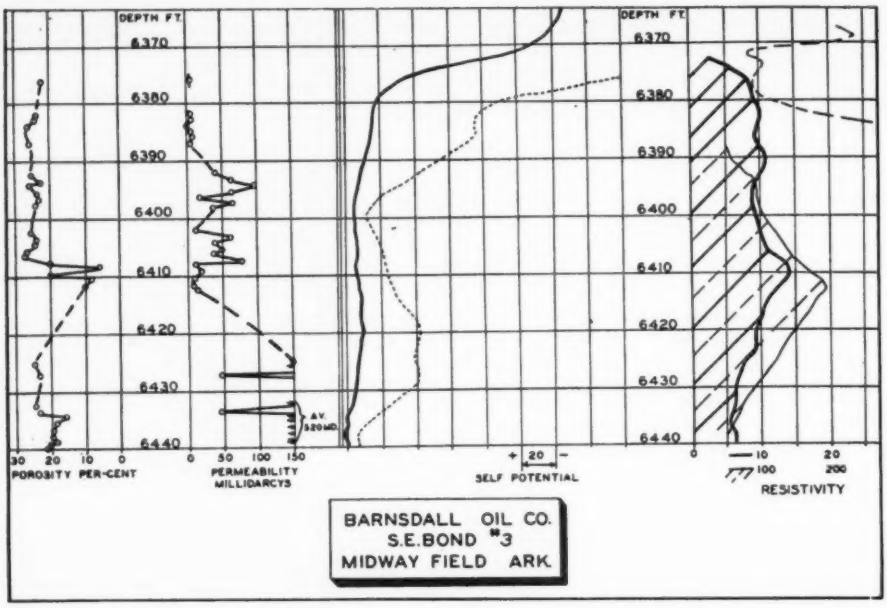


Fig. 4. Coregraph and electric log, Barnsdall No. 3 Bond

that pressures required to inject at a given rate have not increased may be taken as an indication that the water injection had not plugged the formation.

Results of injection. Ordinarily the allowable rate of production for a field in Arkansas after having had a pressure decline of ½ lb. per sq. in. per day would have been ordered reduced. However, the Arkansas Oil and Gas Commission recognized favorable possibilities when plans for experimental injection were submitted for approval February 24, 1943; and, consistent with its progressive attitude, ordered that the allowable per well remain substantially unchanged at approximately 175 bbl. per day following the hearing April 6, 1943. The commission again renewed its order on July 21, when evidence of success was submitted at the statewide hearing. The value of the injection was aided greatly by the fact that individual well allowables were held constant for 5 months prior to the start of the experiment, and have since remained unchanged.

Therefore, in the major portion of the field, where no changes in withdrawals have occurred, pressure history since the start of injection might be interpreted freely as a measure of the effectiveness of the experimental system for augmenting the natural water encroachment. Because pressure measurements made since May 1 show no great change, it follows that injection was maintained at a rate sufficient, together with the natural drive, to replace the fluids as withdrawn.

The first effects on reservoir pressures were observed in wells nearest the input well. As of September 14, two offset wells averaged approximately 2690 lb. per sq. in.; two other wells about one mile away—one mile from the input well—averaged 2640 lb. per sq. in. as compared with 2600 lb. per sq. in., the pressure expected for each of the 4 wells if there had been no injection (Fig. 7). The indicated pressure gradient of 50 lb. per sq. in. per mile is significantly low.

Permanent injection and brine-disposal system. Construction for expansion of the injection facilities is under way. An agreement recently entered into by the six operators in the field at Midway specifies a system of four input wells to be furnished water under pressure from a central plant, which plant is to be supplied with water from shallow water wells and brine from a salt-water gathering system (Fig. 8). The cost of the complete project is estimated at approximately one-tenth of the development cost for the field, exclusive of geological and geophysical expense. It provides for permanent brine disposal and for a flexible program of water input.

Predictions of recovery and water requirements. The capacity of the several productive shallow water wells in the field averages about 2500 bbl. per day per well. The shallow water sands are found at depths from 120 ft. to 450 ft., and extend in an area covering the major portion of the field. For the present rate of withdrawal, it is calculated that the maximum amount of fresh water required will be 8000 to 10,000 bbl. per day, increasing gradually to that amount from the present requirement of 3000 bbl. per day (Fig. 9). Increased rates of oil withdrawal or increased bottomhole pressures will require more rapid injection (Fig. 10).

In order to anticipate the amount of salt water to be handled and injected with the extraneous fresh water required, calculations were made based on conservative conditions. It was assumed for the purpose of calculation that the water drive is to be entirely lateral, and that edge water encroachment is the displacing force. It was assumed that the encroaching edge water moves through each layer of formation at a speed proportional to the permeability of that part, and that all of the

Fig. 5. Pressure-production history

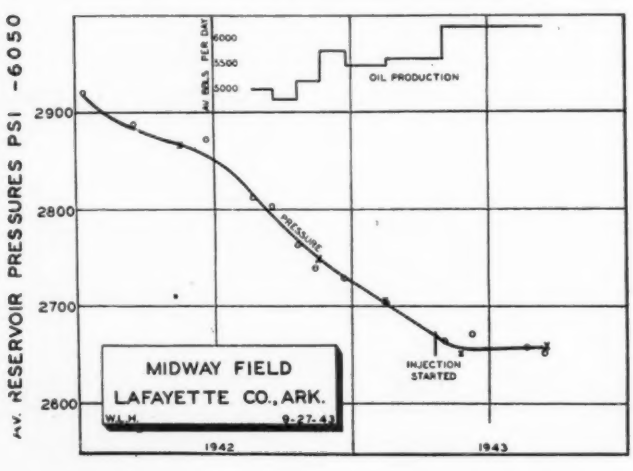
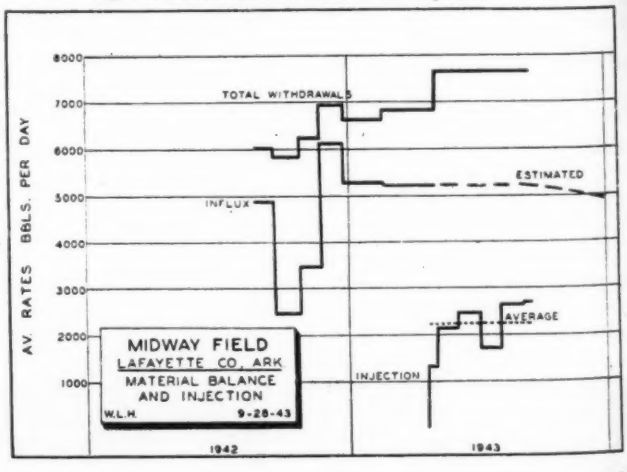


Fig. 6. Material balance and injection



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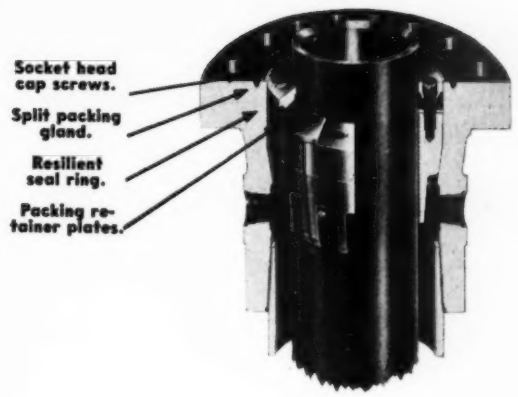

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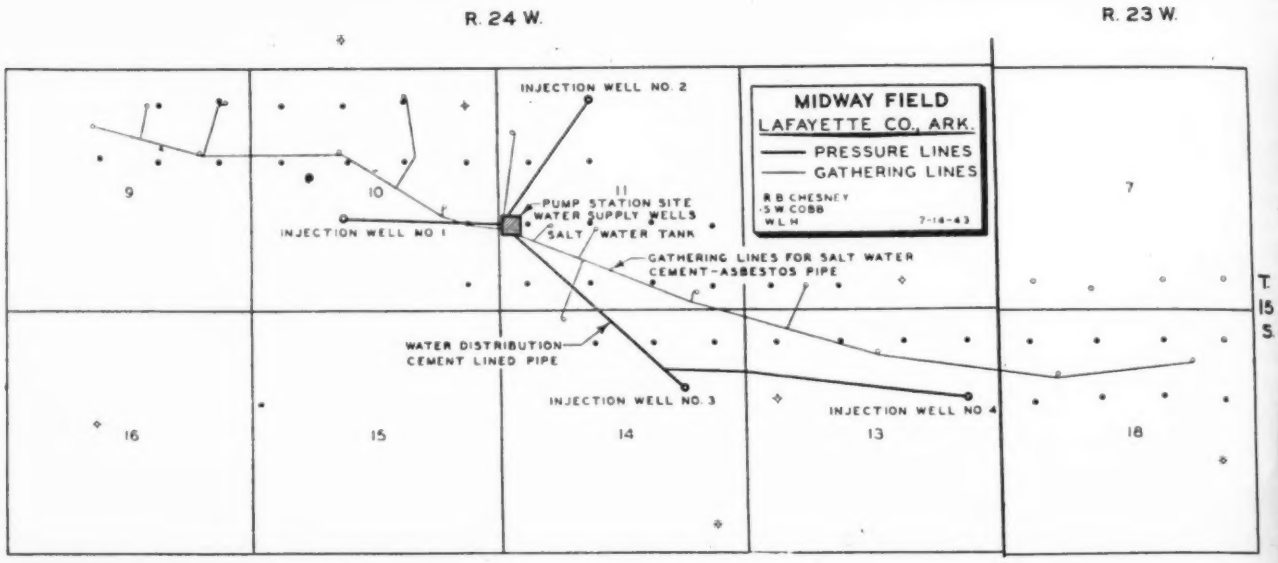
Fig. 8. Map showing lines and wells for injection project



water which will move through the more permeable zones after they have been flushed must be produced in order to recover oil from the formation having low permeability. These assumptions obviously make no allowance for the possibilities of selective completions, nor for the success of workover jobs for reducing the amount of water production. Technological advances, however, can reasonably be expected to provide means for effectively reducing water percentages in the future. It is likewise conservative to expect that the pressure-maintenance program will provide sufficient energy to induce vertical movement of the water table through much of the formation of low permeability, which otherwise would be bypassed by a strictly lateral drive. Statistical analysis of the permeability measurements has been applied—showing that, without control over water production, the combined rate of fluids to be injected could exceed 22,000 bbl. after 20 years of production at 6500 bbl. per day. On the assumption that greater injection capacities would not be provided and that no decrease in reservoir pressure is desired, the rate of oil production then is shown to commence to decline—decreasing in proportion to a rise in salt water production. An ultimate yield of 67,000,000 bbl. is calculated under the conditions stated.

A yield of less than one-half of the amount is calculated for production without injection, the difference being due to the limited volume of natural influx expected. Natural influx here is dependent on expansion of water from the definite volume of Smackover limestone known to be connected to the pool. From these facts, it is calculated that less than one-ninth of the desired quantity of water can enter the pool during its productive life if unaided by injection. The resulting partial water drive can cause only partial recovery of oil.

Pressure predictions. Five months of water injection at Midway has shown indications that natural water drive has been augmented by the use of one input well. By the use of additional injection wells, properly located so as to aid more uniformly the natural water drive

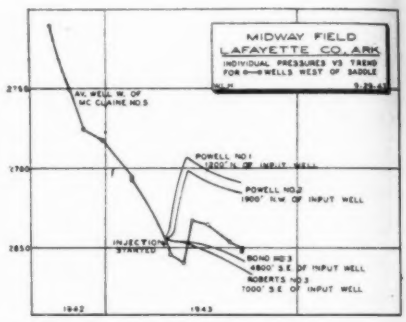


Fig. 7. Individual pressures, four wells, vs. trend for wells west of saddle

under the pool, it is expected that considerable control can be exercised over the pressure behavior of the field. Pressure-prediction calculations, following methods described by W. A. Bruce,[8] are used to show graphically (Fig. 10) that pressure may be controlled even to the extent of being increased, while at the same time increasing the production rate—provided the proper amount of extraneous water is injected, together with all of the brine produced.

Choice of an optimum pressure for

Fig. 9. Influence of injection on yield

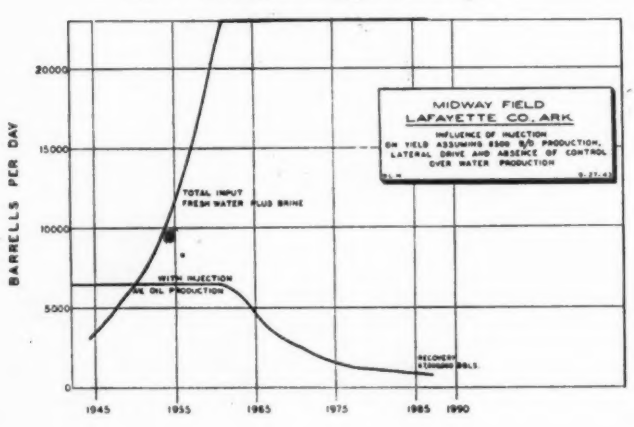
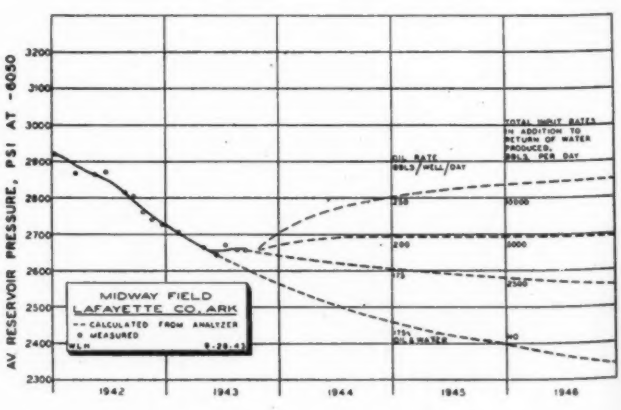


Fig. 10. Influence of injection on pressure-production trends



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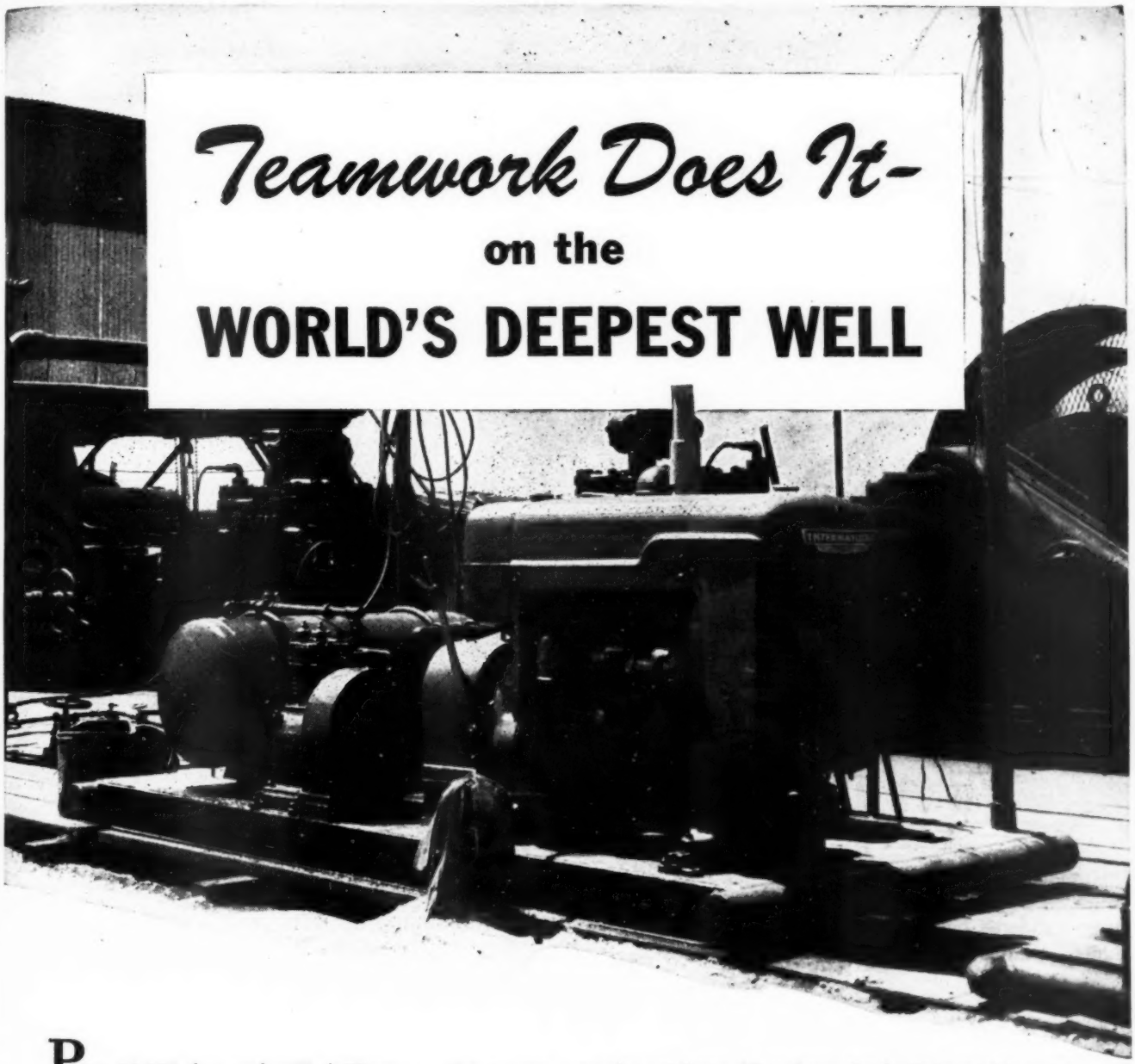

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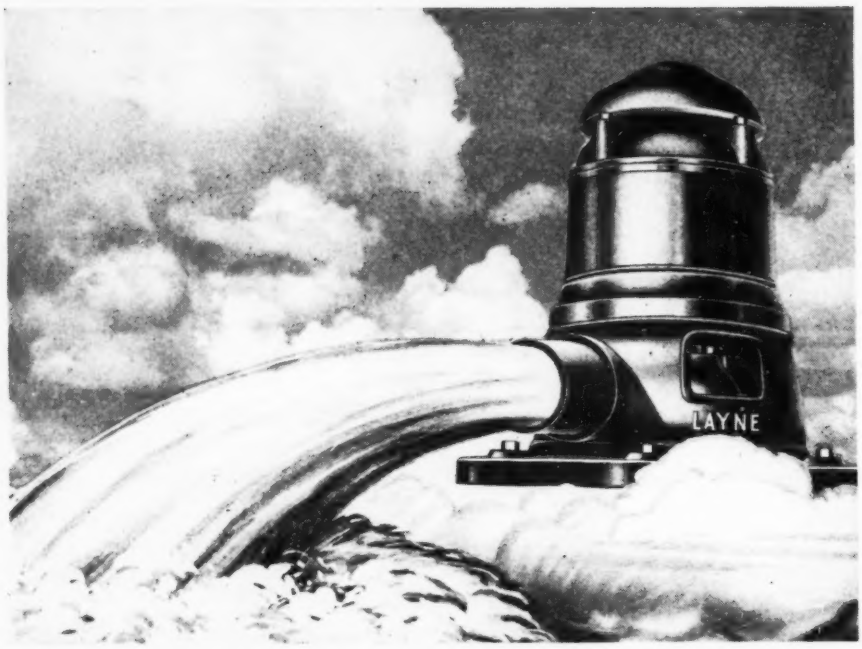

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the reservoir will depend on several factors including cost of injection, productivity index of individual wells, percentage of water in fluid produced, and rate of production. It appears to be feasible, and it may be found to be profitable, to raise the reservoir pressure considerably above the original pressure in order to keep most of the wells flowing. Although maximum productivity and greatest ultimate yield are of first importance, engineering consideration of lifting methods presents additional interesting possibilities in connection with a long-range program of pressure maintenance by this method.

Conclusions. The results obtained at Midway will invite the adoption of this practice in other pools. Careful study and caution are appropriate when different conditions are met. Under certain conditions other secondary means of control would be found preferable. In many similar reservoirs, however, there is every likelihood of its successful and profitable application.

Acknowledgment. The writers gratefully acknowledge valuable aid rendered the experiment by production, engineering, and geological personnel of Barnsdall Oil Company and by the Arkansas Oil and Gas Commission.

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☆ ☆ ☆

Production Materials

Douglas O. Johnson, Gulf Oil Corporation, has compiled information on what material and equipment have been difficult to obtain under war conditions by the production division of the oil industry. He concluded from his findings that a greater shortage today was manpower instead of materials. The paper was given at the A.P.I. meeting, May, 1944, Tulsa, Oklahoma.

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Flowing Producing Wells in Secondary Recovery*

By ROBERT B. BOSSLER
Brundred Oil Corporation

OUR chief reason for discussing this subject at this time is to report progress on a development that has caused some little talk in this area. We would like to tell what we are doing, because we feel that flowing of producing wells in secondary recovery would be an advance in the means of producing oil. We would like also to tell what we have learned so far, and how we are doing what we are doing, in the hope that others too may do some experimenting to the end that any advantages in the method may be more quickly arrived at, and a simple and economical method of producing be developed and adopted.

Early in the experiments we asked for assistance from the Franklin, Pennsylvania, office of the U. S. Bureau of Mines, Petroleum and Natural Gas Division. The wholehearted cooperation and constructive interest we have received has been of very great assistance and encouragement to the work so far. We feel that our area is fortunate, indeed, to have stationed here men with such a combination of scientific, technical, and practical experience. In this regard it is proper to state here that: (1) The experiment in flowing wells in air and gas drive operation is not a one-man show; (2) that the various members of our company and of the Bureau of Mines staff have contributed thoughts, ideas, and suggestions, and, (3) the speaker is merely the mouth piece for the present exposé. Part of the conditions for the Bureau of Mines participation is freedom to publish any valuable results under their own authorship and auspices.

This cannot be classed as a technical paper. Such would require the presentation of data and evidence to support definite conclusions with regard to various phases of the subject, or with regard to the subject as a whole. This paper can merely recite our experiences to date, and draw a few inferences from them.

Because of the fact that we are flowing some of the wells in our waterflooding operations in Kansas, we propose to discuss very briefly that phase of the subject. We are not yet ready to release figures or data in connection with that venture, hence, we will limit ourselves to methods, etc. The greater portion of this talk will be devoted to the flowing experiments in our air and gas drive leases in Pennsylvania.

*Presented at the mid-year meeting of the board of directors of the Independent Petroleum Association of America, Bradford, Pennsylvania, April 28, 1944.

There are, of course, reasons both for and against flowing of wells in a waterflood. From the economic standpoint, it is obvious that investment costs and operating costs should be lower than when pumping. On the other hand, the lifetime of a flood probably will be longer, capital may not be returned so rapidly, and the ultimate recovery in barrels may be somewhat smaller if the wells are flowed. Peak productions are not so high and production is better distributed when flowing, with the result that federal taxes may be a less serious problem.

We will not be completely sure of all of these factors until the property more nearly approaches final depletion.

As a whole, the verdict based on our experience is in favor of flowing. An added year or two of life will not greatly add to the total cost, a high water to oil ratio can be handled cheaply, and operating costs can be progressively lowered as necessity will require when production declines.

Technically, the flowing of wells producing from shoestring sands does not present the same array of problems that are presented in flowing wells producing from sheet sands. The reservoir can be put under pressure with small risk of pushing oil over to neighboring leases.

Another reason for flowing lies in the fact that the pressure distribution under flowing conditions is not vastly different from that existing under pumping conditions. This fact is not restricted to shoestring sand reservoirs.

In equipping wells to flow in waterflood operations we equip single sand wells the same as input wells. A rag packer (poor man's packer) is placed at the top of the sand and cemented. An anchor, arranged to facilitate washing, extends through the sand. We are now using 1½-in. and 2-in. cement lined tubing for our wells. We pull our casing. The protection of water bearing horizons above the producing sand is not a problem where we operate, and our operation has been fully described to the Kansas State Corporation Commission.

For multi-sand wells, dual or parallel tubing strings are used in input wells. For producing wells, our general practice is to use a single tubing string, perforated opposite each sand. Any of the producing sands can then be isolated for test or control, by use of a small string and packers run inside the larger tubing.

One objection to flowing is that water is held in contact with the sand face of the producing well. To overcome this we would like to call attention to an arrangement suggested by Pennsylvania State College. In this arrangement, a pocket is drilled below the sand and the tubing extended below the packer and into the pocket. Any fluids to enter the tubing must first go into the pocket. This means that with water present, it will be produced first, and oil only will be in contact with the sand face after enough oil has been produced to fill the shot hole and the pocket down to the lip of the tubing.

In regard to the flowing of the producing wells in air and gas drive fields, the questions arise as to whether it can be done, what are the reasons why it should be done, can it be generally applied to all wells or to only a portion of them, and what is the best way of doing it?

There can be no question that wells can be flowed, and our experiments, so far as they have gone, give promise that it may become a practical method of producing oil. We are flowing wells which formerly produced 4,000 to 17,000 cu. ft. of gas daily, and which will develop a shut-in pressure of 140 lb. Such high pressures, however, are not necessary. We are operating one well 1000 ft. deep, producing 1⅓ bbl. per day, at a pressure of 50 to 60 lb. Flow at even lower pressures can be had if the gas volume is sufficiently large.

With sufficient energy available as evidenced by actual experience, why should this energy be wasted and additional energy supplied to pump the wells?

Other reasons for flowing are both economic and technical. We believe that both investment and operating costs will be lower when flowing. It seems evident also that if more of the pressure medium is retained in the reservoir, the reservoir pressure should be built up and a wider area affected. This would mean a more effective use of equipment and horsepower expended. This will follow if the bypassing is reduced, or the produced gas-oil ratio is reduced. This is important and should be stressed here. In some sands or leases, the wells will take in large quantities of air or gas at low pressures. Hence, flowing pressures may not exist. The restoration of pressure to such sands or leases by imposing a back pressure, provided that lease boundary lines or other limitations do not prevent it, will not only make flowing possible, but should produce an increased ultimate recovery of oil as will be discussed under "Manner of Flow."

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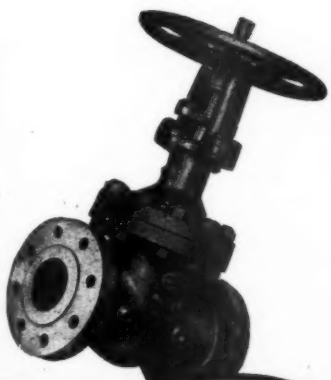

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To be most effective, both from the standpoint of building up a reservoir pressure, and from the standpoint of decreased operating costs, the number of wells and acres should be fairly large.

Flowing of a few wells may be possible, but if pumping equipment must be maintained, part of the benefits of flowing will be lost, and the building up of pressure in the producing sand will be restricted.

It is commonly accepted that five or six types of flow occur in vertical tubing.

In the "Artesian" type of flow, pressures equal to the full weight of the liquid plus friction would be required to produce flow. The type called "Foam" should be more correctly called "Aerated Column." Here the density of the liquid is decreased by the presence of gas bubbles, to the extent that a vertical foot of column may weigh ½ or ⅓ as much as the unaerated liquid. Hence, to flow such a column pressures of about ½ to ⅓ that required to lift an unaerated column of equal height would be required. The type called "Slug" is most common with us and develops when the proportion of gas to liquid increases. This type gives a high velocity to the liquid. The "Film and Mist" types occur as the proportion of gas to liquid increases still further, and are not very efficient. An additional type of flow has been observed at high gas-liquid ratios, consisting of a succession of rings of liquid being blown up the tubing.

The requirements for flow, at pressures less than the hydrostatic pressure as required for "Artesian" flow, are the aeration of the liquid column to decrease its density, and a sufficient volume to give the liquid an upward velocity.

To explain this action, we believe that during the low pressure part of the cycle, both gas and oil are rapidly brought into the well from the high pressure area surrounding the well bore. As the gas pressure builds up, a column of oil forced up into the flow string. As the pressure continues to build up, the rate of liquid production apparently lags behind the rate of gas production until the liquid surface is forced downward by the increased pressure displacing the oil into the flow string, thus permitting the entrance of gas into the orifices.

The advantages of this periodic manner of flow are several. Bypassing is reduced, as evidenced by a smaller gas-oil ratio. In some cases we have produced a barrel of oil with 1000 cu. ft. of produced gas. The values vary from this to as high as 5000 cu. ft. per bbl., but this is still much less than the gas-oil ratio under pumping conditions.

Under this manner of flowing, it is possible that a greater ultimate production may be obtained. During the "build up" part of the cycle, the pressure within a considerable area around the well will be built up. During the "blow down" and low pressure part of the cycle, flow into the well will occur from this high pressure area from all directions. In addition very steep pressure gradients toward the well will exist and it is believed that steep gradients not only produce more oil, but produce it faster. These factors should result in producing more of the oil from the sand in the vicinity of the producing well.

We would like to be able to state what arrangement of equipment is best for producing this periodic manner flow. The truth is that quite a variety of arrangements will produce it. We do not yet know which is best. We will describe what we have done.

Certain natural conditions existing required that part of the equipment take a certain form. As you know, there are in our area three sands; namely, the First, Second, and Third Venango sands. We produce from the Second and Third sands. The First sand is not cased off and will take air at low pressures. This is packed off by placing packers on a string of 2-in. tubing, the packers being set above and below the First sand. The 2-in. tubing extends to the bottom of the hole. This is plugged on the bottom and is fully perforated below the packers to permit the entrance of gas and oil from both the Second and Third sands.

Various preliminary designs of flow strings were tried and considerable information was developed. It was found that ⅛-in. diameter is a practical minimum diameter of orifice to prevent plugging and to permit the entrance of sufficient gas to start a flow. Orifice diameters ranging from 0.028 in. to 0.3125 in. (5/16 in.) were used. For the conditions under which this experimental work is being done, it has been found that 1-in. tubing is probably the best size for producing the periodical manner of flow. It is realized, of course, that the proper size tubing will depend on the gas-oil ratio and the quantity of each being produced into the well bore.

We are now using an arrangement modified after the design of syphons used to dewater gas wells presented in Technical Paper 460 of the U. S. Bureau of Mines entitled "Design and Operation of Gas Well Syphons." A considerable number of modifications were required to produce the periodic manner of flow desired.

In this design, the bottom of the flow string (1 in.) is capped, inlet slots are provided 4 or 5 ft. from the bottom having an area several times the area of the 1-in. pipe. At about 40 ft. above these slots, two or more holes are drilled into the pipe. These are referred to as orifices or jets. We first used brass nipples for this purpose, but found trouble due to incrustations, attributed to electrolysis or "battery effect." We now have in use one string in which a hole was drilled into the flow string, and tapped. Into this was screwed a plug of plastic material, and the orifice drill in the plastic. We have also in use a nipple of "Saran" pipe, which is plastic pipe, of 1-in. iron pipe size, in which the orifices are drilled. Most of our wells are operating using two orifices of 0.120-in. diameter, although some have a diameter of 0.140 in. and in one case, two orifices of 0.3125 in. (5/16 in.) are being tested.

To overcome a corrosion or encrusting difficulty due to water running down the flow string, a sleeve was designed, which is screwed to the outside of a coupling on the flow string immediately above the orifices and extends to a point below them. The bottom of the sleeves or skirt is cut into saw teeth to permit the water to run off the sleeve without the danger of the gas streams picking it up and carrying it up under the sleeve and to the orifices. A little reasoning indicated that this sleeve if of some considerable length might have an added advantage. Without the sleeve, when the gas pressure has depressed the oil surface to expose the orifices and initiate a flow, the pressure on each side of the orifice is equal and theoretically no flow is possible. As the liquid level is further depressed, a slight differential in pressure between outside and inside of the orifice develops, and flow begins. When the sleeve is present, however, and the bottom of the sleeve is several feet below the orifices, appreciable difference exists between the gas pressure at the liquid level and the pressure within the flow string at the orifice level. If the length of the sleeve is 20 ft., this difference in pressure amounts to about 7½ lb. across the orifice as soon as the bottom of the sleeve is uncovered. Because of this increased differential pressure across the orifice, the time and gas required to aerate the column in the flow string, and to start flow, thus should be reduced.

When a well loses its pressure due to some accident or change in operation, the well may "head up" with more liquid than can be raised by the gas being produced by the well itself. In this case, it is necessary to add extraneous air pressure. There are several objections to this and to overcome the difficulty, a modification of the "Chamber Lift" has been designed and is now being tested.

The above section deals with the

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mechanical equipment required. Several other factors more or less inherent in the individual wells are of greater or lesser importance in the operations. We have mentioned the gas-oil ratio and the quantity of each being produced. At sufficiently high gas-oil ratios and volumes, steady flow will occur. This may be prevented by changes in the mechanical design, such as use of larger tubing. The size of the hole at the operating level seems to have an appreciable effect on operation. A small area of liquid surface, as in the unshot well bore, seems to produce short cycles and small pressure differences. A large area, as in the shot portion of the sand, seems to produce long cycles and large pressure differences. The volume of the gas space above the liquid level also has a bearing on the behavior.

A method has been worked out for computing the approximate volume of this space from the pressure and flow data and interesting data are being collected on the comparative values of the volume factor under different conditions.

Conclusions. The number of variables that will affect the behavior of a well flowing as described is quite large and would include the size, number, and position of orifices, and the rates of gas and oil production and their ratio, the size of the hole at the orifice level, and the volume of the gas space. In addition the presence of water, the viscosity of the oil, the built up or restored rock pressure, the depth, and numerous other factors would also enter into the calculation. Listing of the whole array was purposely delayed to this point in order that they should not frighten or cause dismay.

Actually, most of them are of minor importance. This statement is based on the fact that, while the behavior of different wells varies greatly, we get flow under widely varying conditions. Our aim and goal is to discover what are the controlling factors, how to design a simple equipment and so install it that the flow is automatic.

The indications are that this can be done. Given time and opportunity and the kind of assistance we have had, plus some experimentation and exchange of ideas on the part of other producers, we believe that the time is not far distant when a large portion of the air drive production can be flowed with considerable saving. Important saving should be achieved by the reduction of the ratio of gas input per barrel of oil produced.

While it is yet to be proved, it is expected that a greater ultimate production can be obtained.

——— ☆ ☆ ☆ ———

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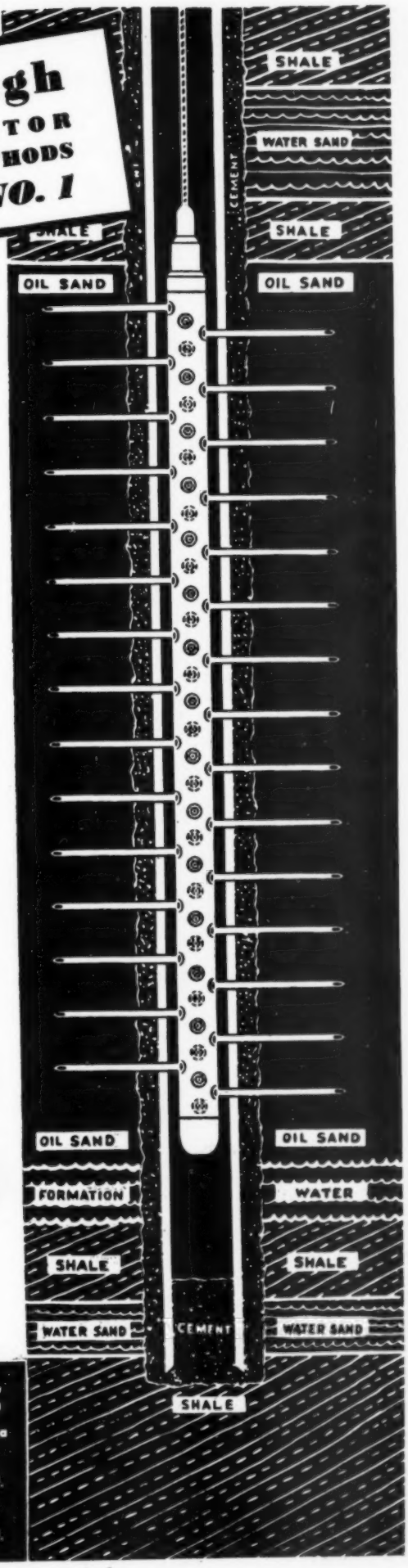

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Fundamental Procedures in Estimating Costs for Secondary Water Flood Recovery of Petroleum*

By ARTHUR C. SIMMONS
Consulting Petroleum Engineer

VALUATION and cost estimates in the oil and gas industry are fundamentally the establishment of a proper relationship between rates of production or recovery and total overall quantitative values. It is possible for rates to be high and total quantities low, such as occur in primary production with low ultimate yields per unit of area.

Prior to the initiation of secondary recovery operations, there are presented a set of conditions where rates are low and total quantitative measurements are large. This condition of rate versus total quantity is quickly changed after the commencement of a secondary recovery project and the problem changes to one where rate of recovery is high with resulting rapid changes in the operating costs per barrel of oil recovered.

Too frequently the proper relationship between variable production rates and changing costs is clouded, and is usually caused by too little consideration of the controlling factors. Such miscalculations have been common in the past few years with the extension of water flooding methods to fields in the Mid-Continent area, and it is hoped that many of the fundamental factors outlined will prevent future economic failures in secondary water-flood operations.

Unit costs cannot be determined without extensive analysis of the many factors involved and it is essential to include all costs rather than use quick comparisons with other historical data. Frequently development costs and operating costs are wholly independent of well depth and yields of oil or barrels per acre recovery.

The detailed methods of cost analysis herein outlined apply to secondary recovery generally but more specifically to water-flood operations. The writer does not possess sufficient data or experience to include the analysis of costs for air and gas repressuring operations in any detailed manner.

The total cost of producing oil by secondary methods must include all items which enter into the problem and for convenience can be subdivided into three major sections, as follows:

1. Land or oil right cost,
2. Development cost, and
3. Operating cost.

Each of these sections will be considered separately.

Land cost. The land or oil right cost is usually a predetermined fixed amount wherein the operator has only limited latitude in its determination. It may represent an existing lease or property or a recent acquisition. The acquisition of land or oil rights for secondary recovery usually takes place by one of the following methods.

(a) Money purchase,

(b) Oil assignment for a specific monetary amount, and

(c) Royalty assignment.

Occasionally a combination of these methods is used in the acquisition of oil rights for secondary recovery purposes. There are advantages to each method and no simple rule will suffice to satisfy the varied problems of the company or individual acquiring oil rights.

With a fixed oil right cost per acre the cost per barrel is, of course, directly proportional to the oil recovery per acre. The only problem in a consideration of the oil right costs is whether sufficient data are available upon which an accurate estimate can be made of the probable oil recovery. Preliminary estimates of recovery are usually made on the basis of core information and correct, accurate core interpretation in new areas is not yet the precision method which it is hoped can be developed in the future. It should be emphasized, however, that the only available method of sampling the producing horizon is with a series of core tests.

Development costs. Development costs should include all facilities, tangible, and intangible, necessary to place the five-spot flood project in operation and are usually included as all drilling equipment, machinery, and installation. The operator has considerable latitude in determining the development costs most suitable to each project. It is necessary to drill and complete a minimum number of wells but by varying the well spacing there is an opportunity to secure an optimum in overall efficiency.

Various operators view differently the importance of equipment items and types of installation and it should be emphasized that individual views and

*Presented before board of directors of Independent Petroleum Association of America, Bradford, Pennsylvania, April 28, 1944.

Fig. 1. Topographic map, secondary recovery "5" spot program. Spacing: 330 ft. by 330 ft. w-w

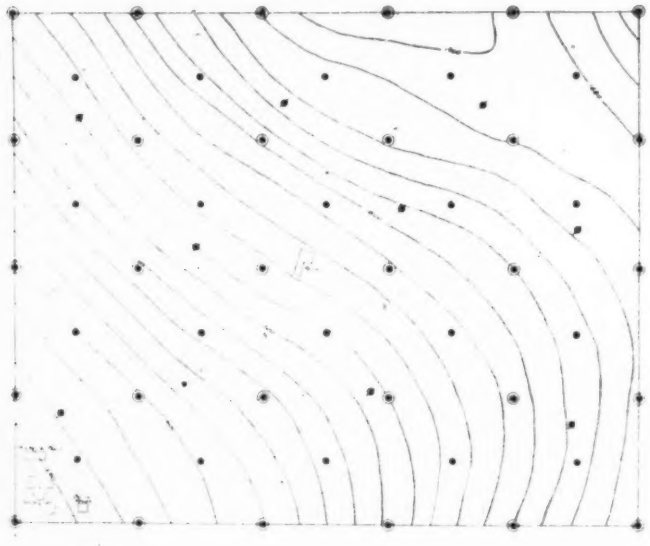
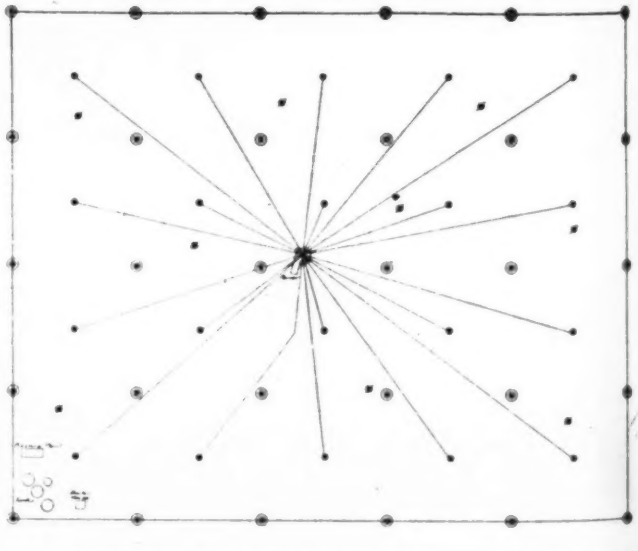
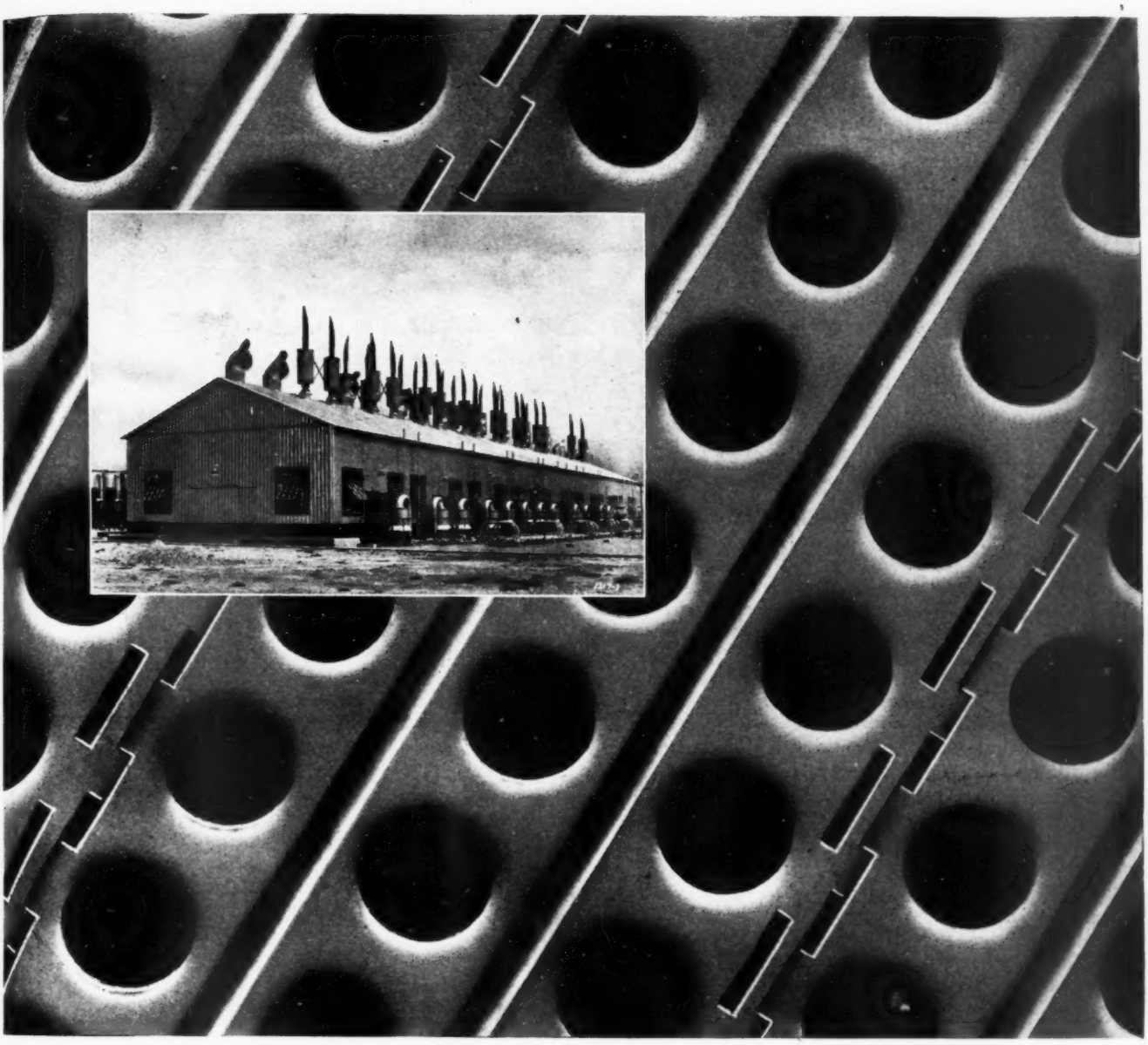


Fig. 2. Pumping power layout, secondary recovery "5" spot program. Spacing: 330 ft. by 330 ft. w-w





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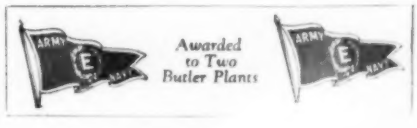

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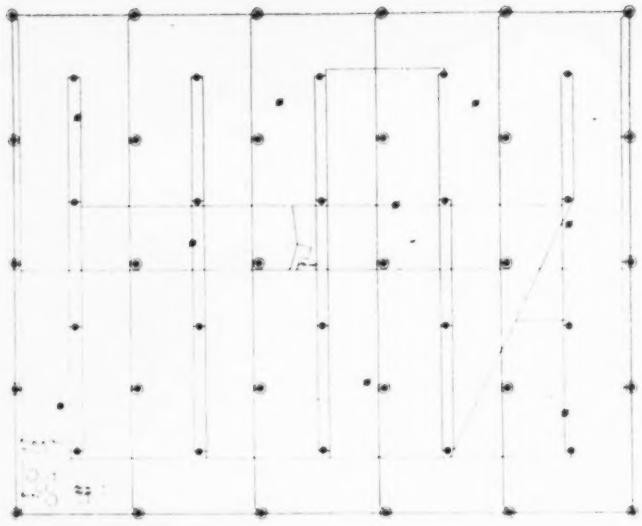


Fig. 3. Oil-gas-water line layout, secondary recovery "5" spot program. Spacing: 330 ft. by 330 ft. w-w

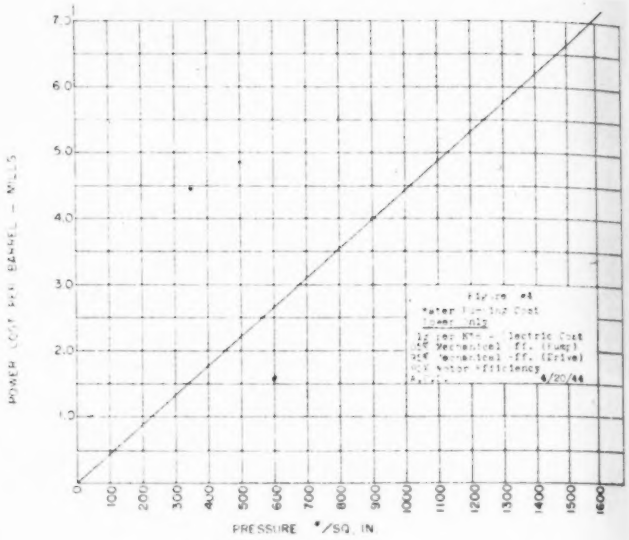


Fig. 4. Water pumping cost, power only

beliefs are in no way criticized.

In determining types of equipment and installation practices, the development costs must be correlated with future operating costs, for it is probable that many development costs have been reduced to an uneconomic limit that at a later date increases the operating cost due to greater maintenance and replacement. A slightly high development cost is perhaps a desirable fault in that repairs and replacements may be reduced to a minimum over the operating life of the project.

Carelessly planned projects usually result in too high development costs and possibly also in too high operating costs, whereas carefully planned projects should result in a desirable development and operating cost.

Many items in development costs are proportional with depth, and other items are proportional to horsepower requirements per acre and quantities of fluid handled. Various approaches can be made in itemizing or segregating a development budget.

In the Bradford field it is a general custom to subdivide the budget into two groups: Wells and other equipment. The custom has also developed into making separate tabulations for average water intake well costs and average oil well costs.

The following description of a five-spot development project in the Bradford area is not intended to represent average costs current in the Bradford field but merely to be illustrative of projects as carried out in the Bradford field, which can be modified to apply to any water flood project in any other field.

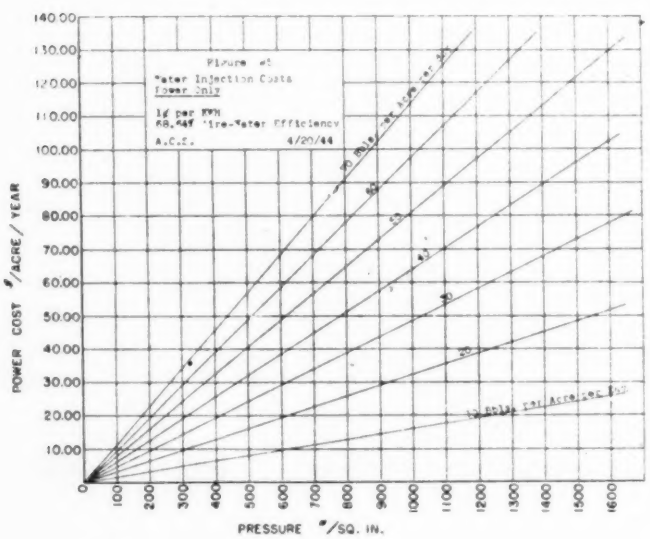
Fig. 1 is a plat of a five-spot project using a well spacing of 330 ft. by 330 ft. (water to water). The project used in this illustration includes 50 acres and necessitates the drilling of 30 water intake wells and 20 five-spot producing wells. For the sake of clarity numbers have been omitted from the wells but in practice all development projects include a system of well numbering which suits a particular condition. The regular pattern of wells that are to be drilled is obvious and the irregularly spaced wells that are included on this plat, with an abandoned symbol, represent the primary drilling.

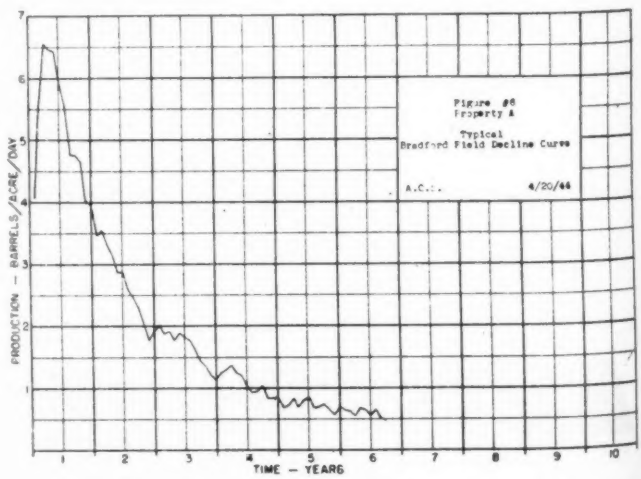
Land subdivisions in Pennsylvania are extremely irregular and the regularity of well spacing common to sectionalized land is unknown in eastern oil fields. The primary drilling took place on what is sometimes referred to as a "buckshot" pattern and, due to the irregular position of the primary wells, it is not possible to utilize efficiently these wells in terms of a patterned or symmetrical redrilling program.

It is a general custom in the Bradford field to abandon and plug all primary producing wells upon initiation of a secondary five-spot project. This custom is not universal as a few operators prefer to reequip the old primary wells and use these wells as producers during the secondary operation.

Fig. 1 is included to show the extreme topography current in eastern oil field operations and to emphasize the

Fig. 5 (left)
Fig. 6 (below)





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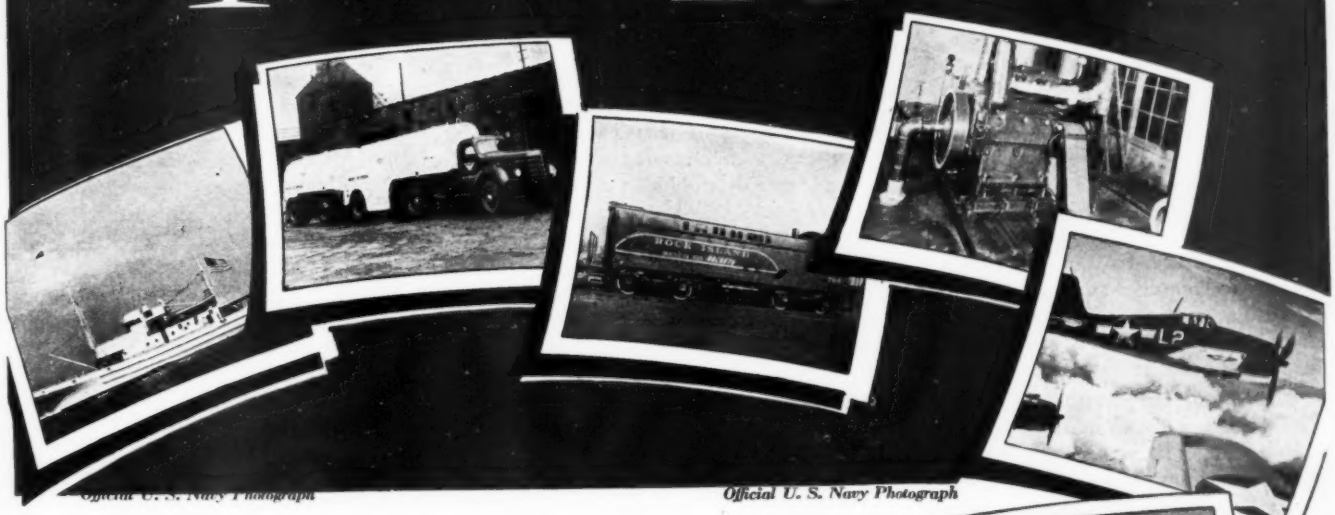

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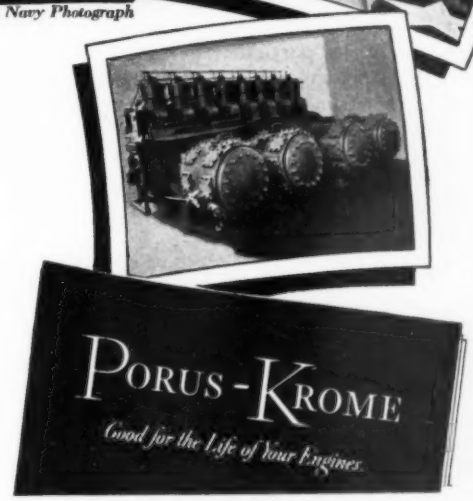

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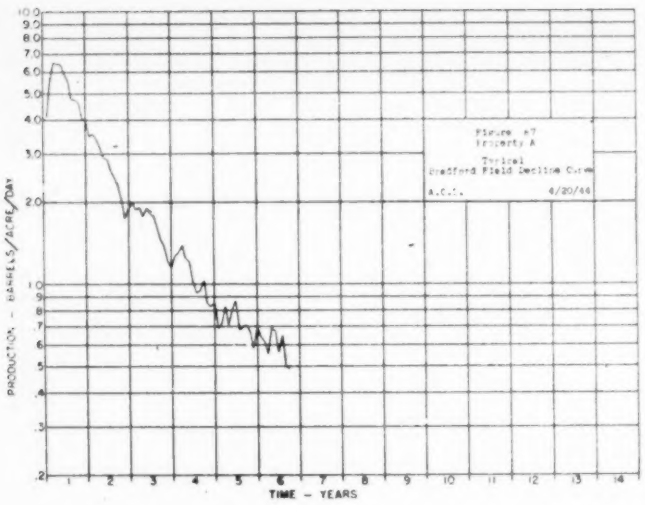


Fig. 7

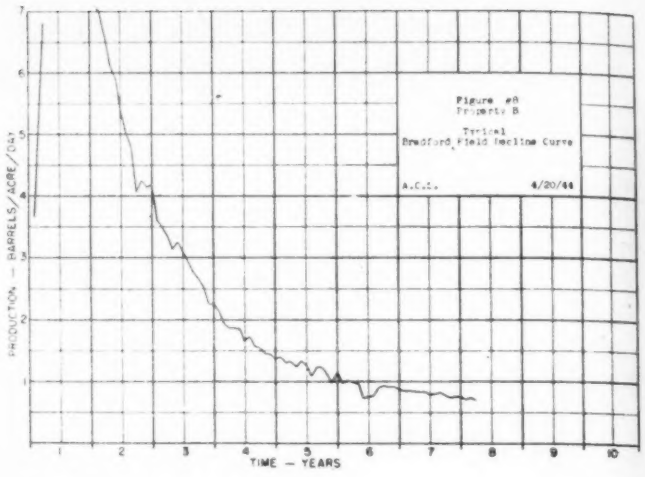


Fig. 8

value and advantage in preparing topographical maps previous to secondary development. It is possible with a topographic map to compute accurately the average depth to the producing sand; to plan and arrange pipe lines for gravity drainage; to limit the installation to the required minimum amount of casing, and to plan for the most efficient installation of pumps, powers, roads, and other surface installations.

The initial preparation of a topographic map is by no means a universal custom but it is possible that such a map would in many instances repay the cost several times. The topography as shown on Fig. 1 is particularly unsuited to a central power installation for the rod lines will require too many hold downs and hold ups for an efficient operation.

A central power installation is shown on Fig. 2 and the rod line layout from the power to the 20 five-spot wells that are to be pumped.

In recent years the use of individual electrically operated pumping jacks has become more general in the Bradford field. A layout of primary and secondary electric lines and the costs of individual pumping jacks can be arranged in the same manner as the arrangement shown which includes a central pumping power.

Fig. 3 is an illustrated layout showing the installation of oil, gas, and water lines. In the early days of five-spot operations in the Bradford field, it was customary to bury the water lines 24 to 36-in. in depth and install the oil and gas lines on the surface. In recent years it has become customary to bury all pipe lines at various depths. If the pipe lines are to be buried, a simplified layout should be arranged, as it is feasible to combine many of these lines in a single ditch thereby lessening the overall installation cost. In the illustration as shown the lines are arranged separately for purposes of clarity.

Water intake well costs. Table 1 is a tabulation of the various items that are to be included in the cost of an average water intake well. The average well illustrated is 1830 ft. deep; requires 400 ft. of surface casing and is equipped with a hook wall packer. The cost as shown is higher than generally current in the Bradford field due principally to the custom of removing the surface casing after the well has been tubed. This would eliminate $260 and the cost applicable to each well would then represent only the deterioration on a string of casing that would be used during drilling and removed after completion.

In Table 1 there is an item of water well tubing representing 1755 ft. of 2-in 4.6-lb. seamless tubing at a unit cost of 24 cents. Most operators, previous to the war, used 1½-in. seamless line pipe in water intake wells at an average cost of 13 to 15 cents. Present limitations on the availability of seamless pipe have necessitated the use of much continuous weld pipe which, in 2-in. size, is available at 12 to 15 cents per ft. Other items in Table 1 are reasonably similar to current costs in the Bradford field. A schedule of this type should be prepared for any new flood development.

Oil well costs. Table 2 illustrates the average cost of an oil well for the project under consideration, and it is

Fig. 9

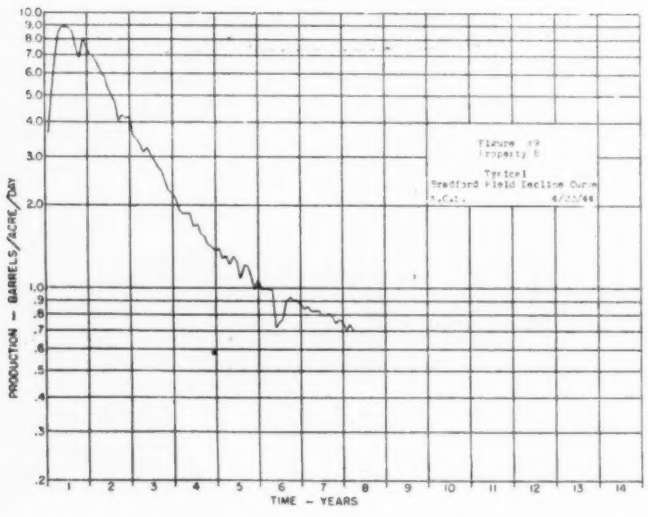
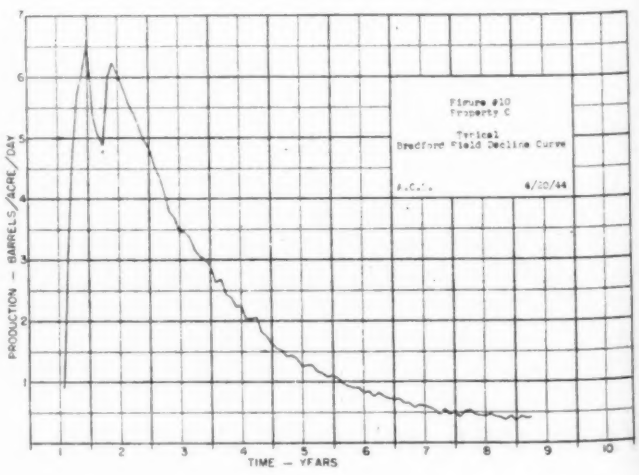


Fig. 10



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√ WHERE DRILLING RECORDS ARE BROKEN

√ WHERE "ROUND TRIPS" RUN UP IN THE HUNDREDS

√ WHERE CONTINUOUS LONG PERIOD OPERATION IS VITAL

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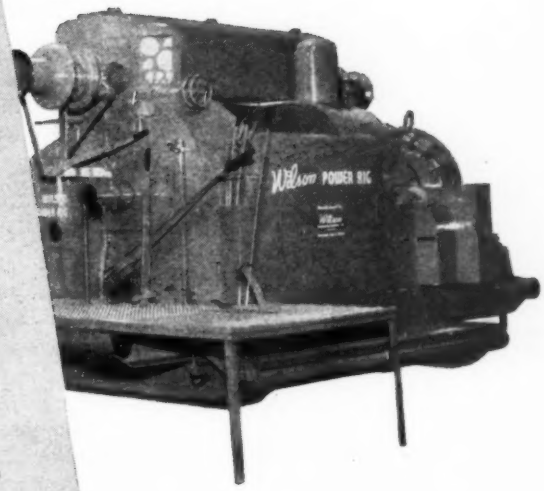

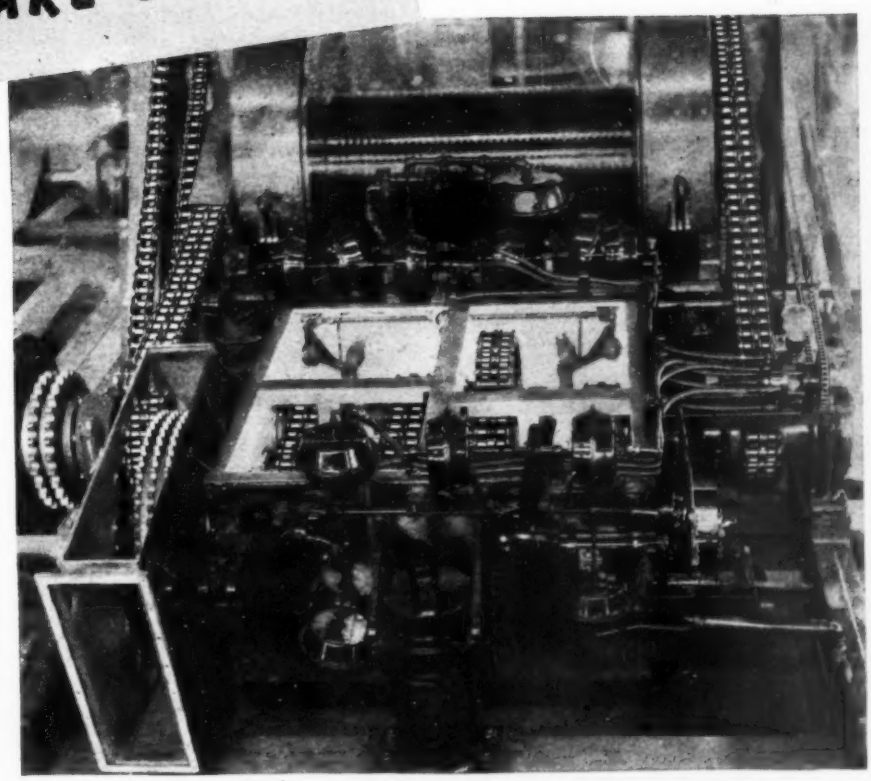

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TABLE 1
Development budget—average water well cost

	Units	Unit cost	Grade or size	Total cost
Casing, 8¼-in.	60 ft.	90c	8¼-in.–17-lb.	$ 54.00
Casing, 6¼-in.	400 ft.	65c	6¼-in.–13-lb.	260.00
Tubing	1755 ft.	24c	2 -in.–4.6-lb.	421.20
Water meter, box and fittings	1			50.00
Packer	1			55.00
Clearing location				25.00
Grading location				25.00
Drilling	1830 ft.	90c		1647.00
Shooting	125 qt.	$1.55		193.75
Cleaning out cost	3 days	$25.00		75.00
Cementing				25.00
Labor and trucking				100.00
				$2930.95

believed that the costs outlined in this table are reasonably current for present day Bradford operations. The items included are universal in the completion of all oil wells in the Bradford field and only minor variations could be made in this arrangement of costs depending on the average depth. In Table 1 the average water well costs $2,930.95 and

TABLE 2
Development budget—average oil well cost

	Units	Unit cost	Grade or size	Total cost
Casing, 8¼-in.	60 ft.	90c	8¼-in.–17-lb.	$ 54.00
Casing, 6¼-in.	400 ft.	65c	6¼-in.–13-lb.	260.00
Tubing	1830 ft.	20c	2 -in.– 4-lb.	366.00
Tubing pump	1			50.00
Sucker rod	1830 ft.	7c	⅝-in.	128.10
Polish rod and fittings				10.00
Stuffingbox				5.00
Casinghead				7.50
Miscellaneous fittings				20.00
Clearing location				25.00
Grading location				25.00
Drilling	1830 ft.	90c		1647.00
Shooting	125 qt.	$ 1.55		193.75
Cleaning out cost	3 days	$25.00		75.00
Labor and trucking				150.00
				$3016.35

Table 2 shows that the average oil well costs $3,016.35, or a difference between the average oil well cost and the average water well cost of only $85.40. In practice, the difference in oil and water well cost is greater due largely to economies effected in the water well cost and it is probable that average water well costs are approximately $500 less than the average oil well costs.

Summary of development costs. In Table 3 there are summarized a total of all development costs for the 50-acre project. Water well and oil well costs have been separately described and are included in this table as multiples of their unit cost. In addition to the oil and water wells it is necessary to install pumping equipment, oil lines, gas lines, water lines, water pressure plant, and various other items. Future developments, particularly in other areas, do not necessarily conform with the equipment and installation items shown on Table 3.

When producing wells in a new project are to be flowed, rather than pumped, it is possible to eliminate all pumping equipment. Producing oil wells that are to be flowed are frequently completed in a manner similar to the water intake wells, and the flowing of five-spot producing wells materially lowers both development and operating costs.

The water supply system is included in the summarization table at $3000 and it should be emphasized that an adequate water supply system is seldom inexpensive and varies in cost from an amount less than shown to difficult conditions where a system costs several times the amount included. A tractor and a lease truck and other service equipment may not be required for each project, as it is possible that such equipment is available on adjacent or nearby projects.

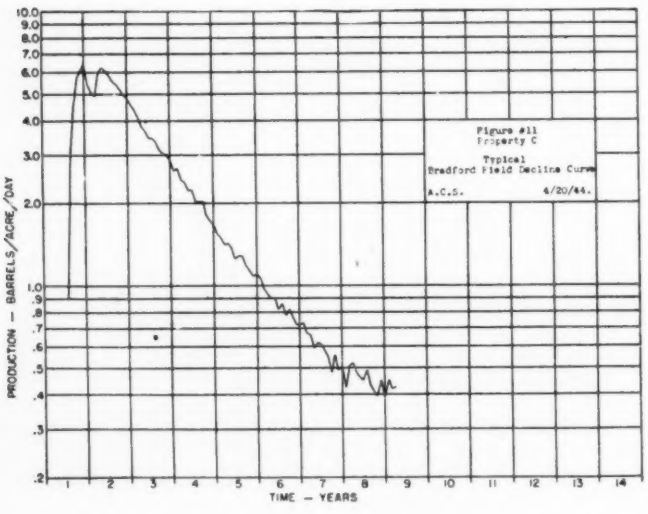
Coring and sampling have been included in the summarized development cost at $7500 for the 50-acre project. Few operators include an expenditure of $150 per acre for coring and sampling although a practice is currently in vogue that involves the chip sampling of many or all water and oil wells, which increases total development costs by $300 to $600 per acre. A better arrangement would include coring and sampling as the first item on a development budget for it is essential to obtain first certain factual information about the producing sand. Frequently coring of an oil sand is a method of getting information whereby operating troubles and problems can be solved and it would seem as though the best practice would require coring previous to any development, and core wells located and completed previous to any other well completions.

The summarized development schedule indicates a total development cost of $4,116.71 per acre. This amount is

TABLE 3
Development budget—summary of development cost

	Units	Unit cost	Total cost
Water wells	30	$2,930.95	$ 87,928.50
Oil wells	20	3,016.35	60,327.00
Pumping power	1		9,000.00
Rod lines	12,380	0.25	3,095.00
Pumping jacks	20	100.00	2,000.00
Oil lines			
2-in.	6,930	0.35	2,425.50
Gas lines			
2-in.	5,500	0.25	1,925.00
3-in.	1,408	0.55	774.40
Water lines			
2-in.	7,400	0.45	3,300.00
3-in.	2,100	0.60	1,260.00
Stock tanks	3	800.00	2,400.00
Separator	1		400.00
Vapor recovery system	1		1,000.00
Boiler and house	1		2,000.00
Water pressure plant	1		10,000.00
Water supply system			3,000.00
Tractor and truck			4,000.00
Tools—tool house			2,500.00
Engineering and surveying			1,000.00
Coring and sampling			7,500.00
			$205,835.40
Total development cost per acre			$ 4,116.71

Fig. 11 (left)
Fig. 12 (below)



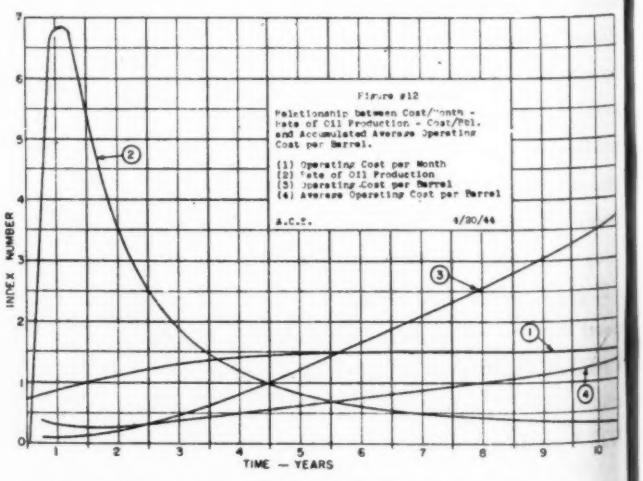


Figure #12
Relationship between Cost/Month - Rate of Oil Production - Cost/Bbl. and Accumulated Average Operating Cost per Barrel.
(1) Operating Cost per Month
(2) Rate of Oil Production
(3) Operating Cost per Barrel
(4) Average Operating Cost per Barrel
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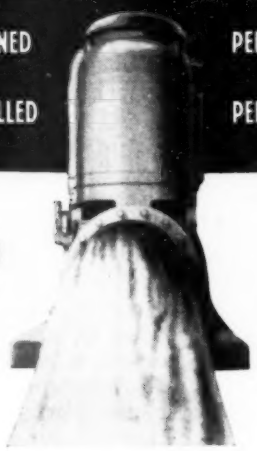

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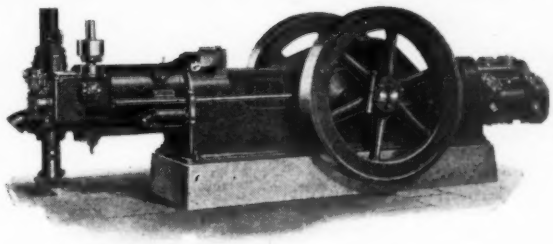

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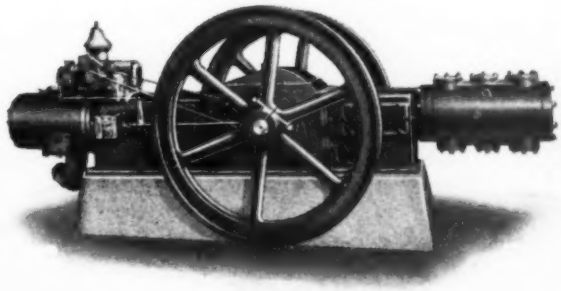

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above current average costs in the Bradford field, which are believed to average $2500 to $3500 per acre.

Adjoining property owners often divide the cost of completing and operating the water intake wells located on a common property line. In this illustration there occur 18 "line water wells" and the total development cost on the 50-acre project could be reduced as much as $27,000 with a division of the cost of the line or boundary water intake wells.

The greatest single factor influencing development costs is well spacing or well density. In the early days of five-spot flood operation in the Bradford field it was customary to space wells 225-250 ft., water to water, whereas at the present time it is customary to use a well spacing of 300-350 ft., water to water. Many items in a development cost budget are directly proportional with well depth; however, a large number of items and a substantial portion of the total cost, is wholly independent of well depth and is proportional to the required horsepower per acre.

As an example, the pumping power installation outlined in the illustration is budgeted at $9000 and will serve 20 producing oil wells at a depth of 1700-1800-ft. The same pumping power and same cost would be required in an area where the wells are one-third this depth but which produce three times as much fluid per day as the average producing well in the Bradford field.

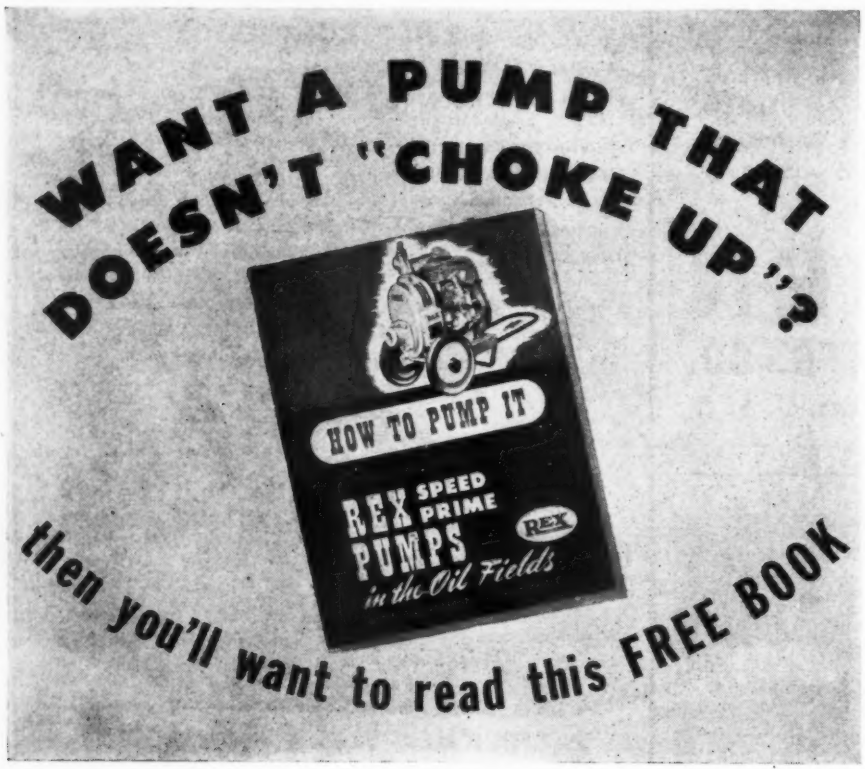
The pressure plant cost could be reduced to a cost per horsepower and may have no relationship with well depth. It is a certainty that oil, gas and water lines, tanks, etc., will cost proportionately to the fluid transmitted rather than well depth. A careful measurement of development costs per acre is frequently obscured by a disproportionate size of some of the facilities. It is unfair to charge a single operation with the entire cost of a water pressure plant or supply system which will ultimately serve a larger area.

Development costs can be safely projected provided there is available sufficient information with respect to the specific conditions. Individual items of equipment should be carefully selected to serve a particular situation, for major replacements in the early life of a flood add a burden to the total cost, and in many instances replacements cannot be made in the later stages of the flood operation.

Operating costs. Various methods of accounting procedures include different items in operating costs. The common term "lifting cost" used extensively in the oil industry is extremely misleading and relatively meaningless unless properly defined. In this analysis the term "operating cost" is used, and at least from the standpoint of engineering estimates, the term "operating cost" should include *every item of direct and indirect cost.*

The operating cost per barrel is always an interesting statistical fact, but in preparing estimates of operating costs, and projecting these estimates into the future, it is fallacious to make such estimates on the basis of an operating cost per barrel, without a careful analysis and projection of such costs with respect to time. Too frequently operating costs are quoted, discussed, and estimated on a per barrel basis, and in many instances the operating cost of a secondary water-flood project is some constant per year entirely independent of the barrels of oil recovered.

Secondary five-spot operations are always expensive and the high cost of operating such a project is largely due to labor, power, or fuel requirements and maintenance. The labor cost is extremely variable, so much so in fact that it has been largely ignored in this discussion, but labor costs can usually be projected on a straight line basis at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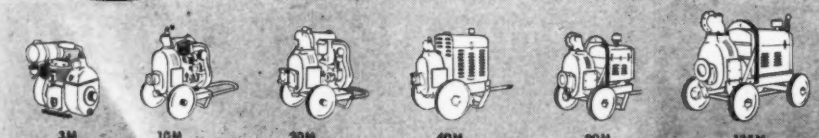

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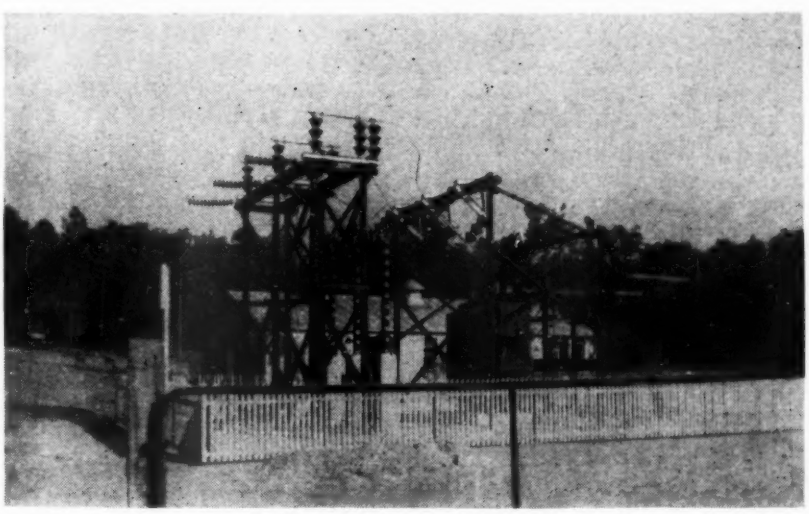

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Photo at top: Shows 3-3750 transformers stepping down the high line voltage from 33,0000 volts to 2400 volts for use in pump station on Big-Inch and Little Big-Inch lines.

Photo at left: Shows 1-3750 KVA transformer located at pump station No. 4 near Hot Springs, Arkansas, served by 110,000 volt power line stepping down the voltage to 2400 volts for the motors on the Big-Inch Pipe Line.

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a fixed amount per month, or per year, or per acre per year. It is a certainty that the labor cost of flood projects will be higher per month just previous to abandonment when the lease is producing 25 bbl. a day than it was some years previous when the property was producing at a rate of 500 bbl. per day or any multiple of these amounts. The increased cost per barrel is tremendous.

Operating records. Good operating records are essential for efficient control of any water-flood project and such records should include physical facts, such as, water injected, oil produced, injection pressures, various maintenance operations, the usage of electricity, fuel oil, and supplies and complete financial records. The financial records should be sufficiently subdivided so that an accurate historical record is compiled of the cost of various items, such as, labor, fuel, water, pulling, maintenance, repairs, etc. Because of rapidly changing relationships, it is desirable to arrange financial records to reflect the current period and an accumulated record of all operations to date.

Water supply costs. Water supply and injection costs represent a substantial portion of the total operating cost, and water supply and injection costs are probably constant or reasonably constant throughout the life of the operation. Water costs are frequently hidden in general operating costs as it is difficult to segregate various items of maintenance and labor and allocate such items to water costs. Conditions throughout the Bradford field are variable with respect to water costs and other flood projects show even more varied water costs than Bradford field operations. The direct cost considered in this discussion is power cost only, and an approximation will be made as to average total water costs in the Bradford area.

Fig. 4 is a plot of power cost for pumping water at various operating pressures. The power cost has been computed in terms of electrical measurements as this is a more simple method of computation than that involving oil or gas engines.

A large amount of purchased electric power is used in the Bradford oil field, but it should be distinctly understood that this discussion does not advocate the use of purchased electric power unless in its overall aspects, such purchases represent the most economical form of power. The use of gas engines for power is most common where lease gas is available and in many instances gas is purchased for the continued use of the gas engines after the lease gas has become insufficient or exhausted.

It is believed that, in the Bradford field, the lease gas available for water-flood operations will amount to 500,000-1,000,000 cu. ft. per acre resulting in a value of $300-$600 per acre. These gas reserves are available on each property in the Bradford area, but in many other fields the gas reserves are entirely depleted at the start of water-flood operations and it is consequently necessary to purchase fuel or power from the start of operations.

The chart (Fig. 4) is applicable only for the conditions as shown, that is, 1 cent per kw.-hr. electric cost; 85 per cent mechanical efficiency (pump); 95 per cent mechanical efficiency (drive); 85 per cent motor efficiency. These efficiencies result in an overall wire-water efficiency of 68.64 per cent.

It is interesting to observe that at 450-lb. pump discharge pressure the power cost is $0.002 per bbl. whereas at 1600-lb. pump discharge pressure the power cost is slightly over $0.007 per bbl. It is a generally accepted precept in the Bradford field that the maximum permissable pressure is the most efficient in terms of oil recovery but it should be realized that such increased operating pressures increase materially the total operating cost.

Fig. 5 is an amplification of Fig. 4, wherein pump discharge pressure is plotted against power cost in dollars per acre per year for various rates of water injection from 10 to 70 bbl. per acre per day. Water injection rates are partially independent of oil recoveries and this chart includes power costs only, to which must be added the many other costs to determine the total water injection cost.

At an injection pressure of 750 lb. and an injection rate of 20 bbl. per acre per day, the annual power cost per acre is approximately $25, and at an injection pressure of 1500 lb. and an injection rate of 30 bbl. per acre per day, the annual power cost is approximately $75 per acre.

Water supply and treating costs in the Bradford field vary from a minimum of $0.001-$0.002 per bbl. under favorable conditions to a maximum of $0.020 per bbl. under conditions of adverse supply. It is probable that total water costs in the Bradford area average $0.015-$0.03 per bbl. for high pressure water. If the power cost is $75 per year, and this represents only one-third of the total cost, then water injection costs will total $225 per acre per year or $2250 per acre over a 10-year period. This cost may be strictly independent of the oil recovery obtained. Water costs and nearly all other costs should be projected into the future on a per acre, per month, or per year basis.

Relationship of production rates and costs. It was originally planned to include actual historical costs on a few properties, but upon inspection and study, these costs were so irregular and varied that it appeared more desirable to establish the theoretical relationship, from which costs can be estimated and projected for any development. There exists a general relationship that operating costs are relatively constant with time and the production rates change in conformance with some type of decline curve.

Bradford field decline curves are varied and irregular dependent upon spacing, pressure, shooting, permeability, and other factors, but many Bradford field decline curves adhere to a generalized pattern. The decline curves that will be shown represent three properties of different size, owned by different operators, and separated many miles from each other. The three curves have been plotted both in arithmetical and semi-logarithmic scale and the data have been arranged to show rate of oil production in terms of barrels per acre per day.

Bradford field decline curves. Fig. 6 is an arithmetical plot of a decline curve for property "A." This property reached a peak production of 6.5 bbl. per acre per day and in 6¾ years had produced a gross recovery of 4800 bbl. per acre and had a producing rate of 0.5 bbl. per acre per day. Fig. 7 is a plot of the same data on semi-logarithmic scale. All Bradford field decline curves have a tendency to show a straight line decline trend with semi-logarithmic plot. The straight line trend does not continue for the later years but may be interpreted as another straight line trend with a change in slope. The primary decline trend during the first four years of operation is at the rate of approximately 4½ per cent per month.

Fig. 8 is the arithmetical plot of production data from property "B." This property reached a peak production of 9.0 bbl. per acre per day and has yielded a gross recovery of 6000 bbl. per acre, and is currently producing at the rate of 0.7 bbl. per acre per day. The same data are included on Fig. 9 as a semi-logarithmic plot. The primary decline trend during the first 4 years of operation is approximately 4¼ per cent decline per month.

Fig. 10 is the arithmetical plot of production data from property "C." This property reached a peak production of 6.5 bbl. per acre per day and has produced a gross recovery of 6100 bbl. per acre, and is currently producing at the rate of 0.42 bbl. per acre per day. Fig. 11 is the semi-logarithmic plot of production data from property "C." The primary decline trend over a six-year period is at the rate of approximately 3¾ per cent per month.

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Producing rates of 8-10 bbl. per acre per day were fairly common in the Bradford area on properties yielding 5000-7000 bbl. per acre recovery. Lower recovery properties attain peak or maximum producing rates of 4-8 bbl. per acre per day. In the Mid-Continent area producing rates of 10-20 bbl. per acre per day, at peak production, have been obtained on the more favorable projects and lower "peaks" on the lower yield areas. One unusual flood project attained a peak or maximum production of 30 bbl. per acre per day.

It is difficult to obtain good production decline curves in any area for the reason that subsequent increments of development usually obscure the true decline trend. Many decline curves have a broad, flat peak, leading to the belief that such a characteristic is common in the production of oil by secondary recovery methods. The broad, flat peak frequently encountered is caused by time lag intervals in attaining peak production of the various wells, and it should be definitely understood that each well in a secondary water-flood project has a definite producing rate or decline curve that may be approximated and calculated from core information. It is essential to realize the general producing rate characteristics of any project to understand and estimate future operating costs.

Production and cost curve. The relationship of operating cost and rate of oil production is shown on Fig. 12 for a specific decline curve and an assumed operating cost per month curve. The ordinate on this chart is expressed in terms of index numbers and is intended to show only a ratio relationship. Curve 2 is an idealized production decline curve for the Bradford field. Curve 1 is a theoretical projection of operating costs and is based on a presumption that the operating cost per month will double over a five-year period and for the second or last 5 years of operation will remain constant in terms of dollars per month.

In terms of the index numbers, this curve is started at 75 and increased in 60 months to 150, or 0.75 to 1.5. For many projects, the shape of Curve 1 will be different than shown, but it is a certainty that this curve cannot be more favorable than level or constant per month. It is probable that the operating cost per month will rise in the first few years of operation and then maintain a constant or nearly constant rate for the balance of the producing period.

Curve 3 is a plot of operating cost per barrel for the conditions established by curves 1 and 2. The significant part of this curve is that at the end of 10 years the operating cost per barrel will be 37 times the minimum. It should be obvious that if the minimum cost is yielding only a small profit it will be only a short time before the project is unprofitable and uneconomical due to the constantly increasing costs per barrel of oil produced.

Curve 4 represents an accumulated average cost by dividing the accumulated total cost by the accumulated total production. This curve indicates that the average cost over a ten-year period is at least 6 times the minimum cost. To avoid confusion, it should be emphasized that this curve does not represent specific costs except for the assumed conditions for which it was constructed.

All five-spot water flood operations will have similar cost-production rate characteristics, and it would be advisable on any new project to estimate and project specific values for curves 1 and 2 so that curves 3 and 4 can be computed. Too frequently, the margin of profit during peak production is low and estimates of this type would quickly show the total costs to be such that the project is doomed to be unprofitable.

Conclusions. Those water-flood operating projects which have been unprofitable or which may become unprofitable may be segregated into three groups:

(a) Low oil recoveries,

(b) Low unit prices, and

(c) High operating costs.

It is, of course, never possible to provide, with any degree of certainty, against failure of business enterprises but with adequate investigation and preparation of thorough estimates it is hoped that future water-flood operations, particularly in the Mid-Continent area, will attain a higher ratio of financial success. Advance estimates of oil recovery can only be made through core analysis and core analysis interpretations are definitely improving so that more accurate estimates of recoverable oil are now being made.

Little or nothing can be said with respect to future oil prices except that prices in the oil industry have not been favorable for many years, therefore it becomes increasingly important to estimate accurately the oil recovery and future operating costs.

It is hoped that this discussion of operating costs on secondary water-flood operations will dispel many of the previous illusions wherein operating costs were estimated and allied too closely with the oil recovery. Operating cost on all secondary water-flood operations should be estimated and projected into the future on a per acre-per month or per year basis.

—— ☆ ☆ ☆ ——

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Role of Connate Water in Secondary Recovery of Oil*

By PARKE A. DICKEY, Forest Oil Corporation, and
ROBERT B. BOSSLER, Brundred Oil Corporation

IN recent years laboratory work has led to a much better understanding of the principles of oil-reservoir performance. The general principles of the expulsion of oil from sandstone by gas or water were developed by geologists of the Second Geological Survey of Pennsylvania in the 1870's[1] but only recently has the merchanism of gas or water drive been intensively investigated. Most published articles have applied the facts established in the laboratory to the primary production of oil from flush fields. This paper is not based on any new observations, but is an attempt to apply some of the conclusions obtained in the laboratory and described in the literature to recovery of oil from depleted pools by secondary methods.

One of the most important factors that determine whether or not a secondary-recovery operation is economically successful is the ratio of injected fluid to oil recovered. This ratio may be expressed as the overall or cumulative gas-oil ratio if gas is the driving medium, or water-oil ratio if water is the driving medium. Recent theoretical and experimental work has shown that the relative amounts of gas, oil, or water that are flowing in a sand at a given point by reason of a pressure difference depend on the saturation of the three phases in the sand at that point. It has long been recognized that a sufficient oil saturation is a requisite to secondary-recovery operations. It has not, however, been sufficiently emphasized that the gas and water saturations are equally important in determining the overall gas or water-oil ratios of the operation. A small variation in the gas or water saturation of a sand may determine whether water or gas can be used most efficiently as the driving medium.

Steady-state flow of fluids through sand. It has been shown repeatedly that most producing oil sands contain appreciable quantities of connate water. The first laboratory determination of the oil content of a sample of oil sand known to the authors was by Charles R. Fettke[2] in 1926. He found as much as 40 per cent water present with the oil, and although he believed, probably correctly, that much of the water may have entered the sand during drilling, he was the first to point out that there was no reason to assume that an oil sand was originally 100 per cent saturated with oil. The significance of the presence of water in an oil sand was not generally appreciated until more than 10 years later.

Schilthuis[3] expresses the opinion that in most places the reservoir rock is completely wet with water and does not contact oil or gas directly. Under certain circumstances it appears possible that oil may be in contact with the solid phase. All normal producing sands, however, contain water, oil, and gas, and it is generally conceded that the water is present in the finer pore spaces, at the junction of grains, and probably wets a large proportion of the internal surface of the reservoir.

The presence of this water, and its position, has a very important effect on the expulsion of oil by either gas or water. It would be expected that the mechanism of the removal of oil from a sand of which the internal surface was entirely wet with oil might differ greatly from the removal of oil from a sand of which most of the internal surface was wet with water. It is seriously questioned whether the results of laboratory work on samples 100 per cent saturated with oil can be applied to a field where the sand contains appreciable amounts of connate water. For example, in the rapid removal of oil from an oil-wet sand by water drive in the laboratory, the water would remain in the larger pores while oil would remain in the smaller ones and on the grain surfaces. This condition would be exactly the reverse of that believed to exist in most producing sands. Conclusions on the behavior of such a test sample would not apply to field conditions.

Wyckoff and Botset[4] showed, in 1936, that when a gas and a liquid were flowing simultaneously through a sand, the permeability to gas decreased as the liquid saturation increased. Similarly, the permeability to the liquid increased as the liquid saturation increased. Similar experiments by others[5,6,7] have checked the validity of this work.

A curve showing the change in effective permeability with liquid saturation, as determined experimentally by Wyckoff and Botset, is shown in Fig. 1. These authors also showed that in steady-state flow the gas-liquid ratio is determined by the ratio of the viscosities of the two phases, and the ratio of the effective permeabilities of the sand to them. This may be expressed:

$$\frac{V_g}{V_l} = \frac{k_g \mu_l}{k_l \mu_g}$$

Where:

V_g = cc. per sec. gas at mean pressure,
V_l = cc. per sec. liquid,
k_g = effective permeability to gas,
k_l = effective permeability to liquid,
μ_g = viscosity of gas, and
μ_l = viscosity of liquid.

Therefore, from the curves of Fig. 1, which give the effective permeabilities of the sand to the gas and liquid, and a knowledge of the viscosities of the fluids, the steady-state gas-liquid ratio may be computed easily.

To date only one study of the flow of all three phases—gas, oil, and water—has appeared.[8] This study by Leverett and Lewis, although exploratory in nature, provides some data showing how the fraction of each phase in the flowing stream changes with the saturation of that phase in the sand.

Mechanism of fluid displacement. Buckley and Leverett[9] have investigated mathematically the displacement of oil by water and gas on the basis of the permeability saturation relationships outlined in the foregoing paragraphs. They show that the fraction of the displacing fluid moving at any given point in the sand depends on the viscosity of the fluid and its relative saturation at that point.

Take, for example, a point in an oil-rich sand that is being invaded by a water flood. Imagine that at this point the effect of the drive is beginning to be felt, but that the water has not yet reached the point. The oil saturation is high and the water saturation is low, so that more oil than water is moving under the effect of the drive. The moving oil displaces the gas, occupying the spaces that the gas occupied. The effect of the flow of fluids ahead of the drive will thus be to increase the oil saturation greatly, increase the water saturation slightly, and reduce the gas saturation to nearly zero. A rich zone thus accumulates ahead of the water front, which is called a "bank" of oil.

As the water reaches the given point, it displaces much of the oil and occupies the spaces formerly occupied by oil. This increases the water saturation of the sand, and therefore increases its permeability to water and decreases its permeability to oil. The proportion of oil in the flowing stream at the point thus decreases very rapidly, and continues to decrease as the water saturation of the sand increases. As the water continues to flow through the sand it will not remove much oil.

The first stage, when the flowing stream is principally oil, was called by Buckley and Leverett the "initial" stage, and the later stage, when the

*Presented before American Institute of Mining and Metallurgical Engineers, New York City, February, 1943.

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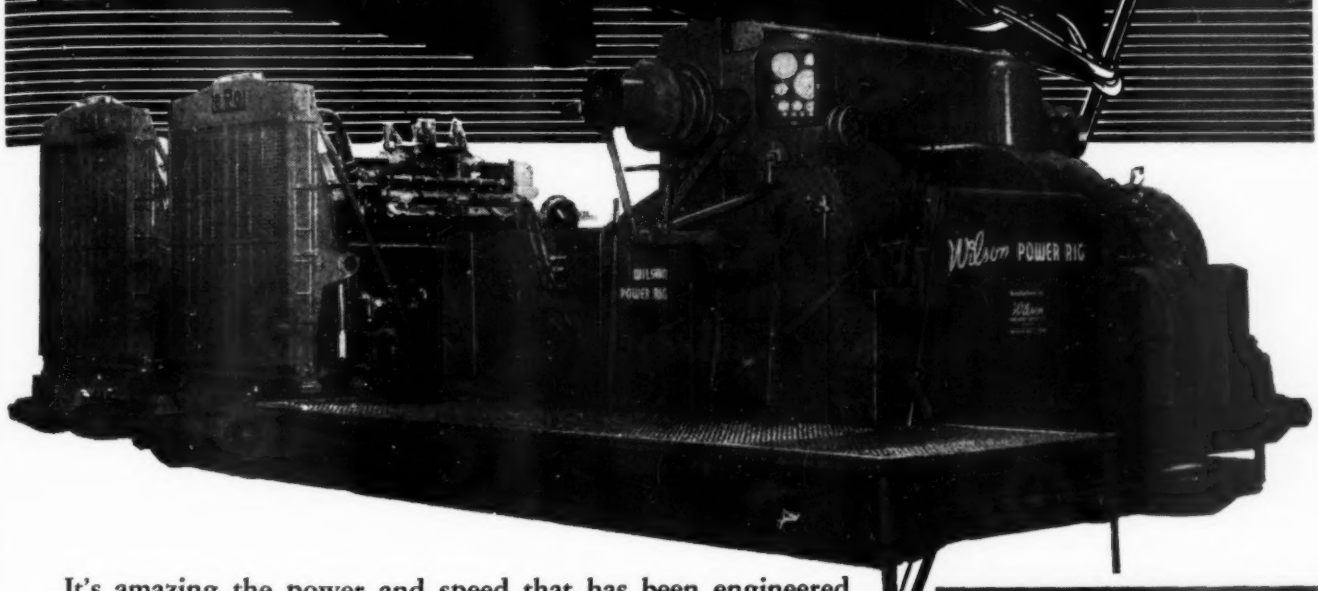

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stream is mostly water, was called the "subordinate" stage. During the initial stage the oil is expelled by a shoving or piston action, and during the subordinate stage it is expelled by a frictional or shearing action. In the subordinate stage, the drive is relatively ineffective, as only small amounts of oil will flow for large amounts of water.

It seems probable that in actual secondary water-flooding operations virtually all the recoverable oil is removed during the initial stage. After the advancing water front reaches the producing well, the water-oil ratio is so high that only small and totally uneconomic quantities of oil are produced. A well will continue to produce oil for a long time after the water has broken through, but this is because certain strata of low permeability are still producing oil although others may be producing mostly water. In a normal flooding operation in the Bradford field, the water production does not begin to increase until oil production has about reached its peak; thereafter, total liquid produced usually increases, the oil decreasing and the water increasing because of the now higher permeability of the sand to water. This indicates that when the effect of the flood has fully reached the producing well nearly all the individual strata, even of differing permeability, are producing oil only. The water front then reaches the well successively in the various strata in inverse order of their permeability. Probably no single stratum produces commercial oil and water simultaneously.

These considerations suggest that in performing water-flooding tests on core samples ("flood pots"), only the oil recovered by small throughputs of water should be considered recoverable. Continued passage of water through the core under high pressure differentials will lead to the recovery of additional quantities of oil in the laboratory, which would be impossible to recover economically in the field.

A similar sort of action takes place when gas is the invading fluid. Initially, if the sand is well saturated with oil, a bank of liquid is pushed ahead of the gas, because the sand is more permeable to oil than it is to gas. As the oil is displaced by the gas, the permeability to gas increases very rapidly, and when the sand contains as much as 20 per cent gas, the gas flow by volume is approximately 20 times that of the oil.[6] This fact has given rise to the opinion, often expressed, that gas drives are fundamentally less efficient than water drives.

It should be remembered, however, that in most places it is uneconomical to attempt to recover oil by water drive after the initial or "bank" stage of displacement has passed, because large volumes of water must be handled to obtain relatively small quantities of oil. With gas as the displacing fluid, the initial stage is short-lived, and effects the recovery of only a small part of the oil even in the early life of a field, and it is never attained under secondary recovery methods in partly depleted pools. However, the low cost and ease of handling makes it possible to drive from 1000 to 5000 volumes of gas through the sand for each volume of oil recovered, hence, under certain conditions, especially those of low oil and high water saturations, gas drives may be much more efficient economically than water drives in the recovery of oil.

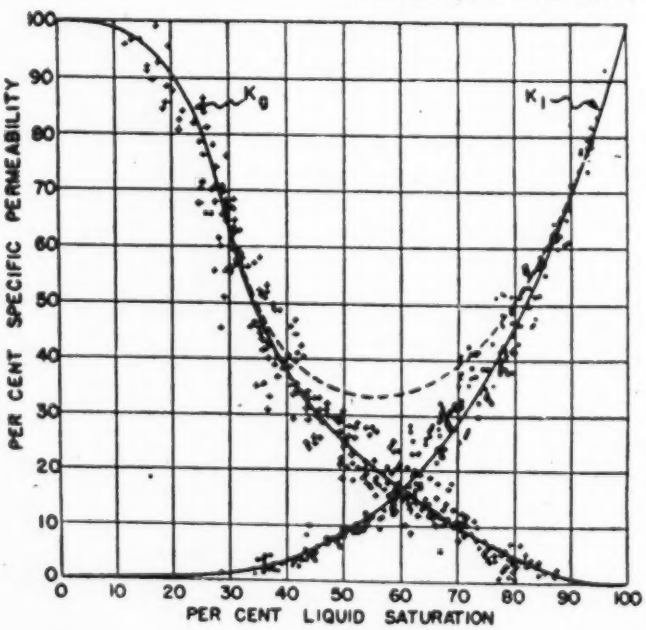
Evaluation of water-oil and gas-oil ratios from experimental data. Leverett and Lewis[8] investigated the flow of gas-oil-water mixtures through unconsolidated sands. Their observational data are tabulated in their paper, and the composition of the flowing stream at various saturations is given. From these data the gas-oil ratios and water-oil ratios of the flowing stream have been calculated. The approximate values of the gas-oil ratio are shown by the curved lines in Fig. 2*a* and the water-oil ratio in Fig. 2*b*. These are triangular diagrams, the purpose of which is to represent saturation conditions existing in the sands being investigated. In these diagrams a sand saturated 100 per cent with gas would be plotted at the apex, while a sand saturated 100 per cent with water would fall in the lower left corner, and 100 per cent oil in the lower right corner. A sand saturated 33⅓ per cent with each component would fall exactly in the center of the triangle. Every possible saturation will thus appear as a point in the diagram.

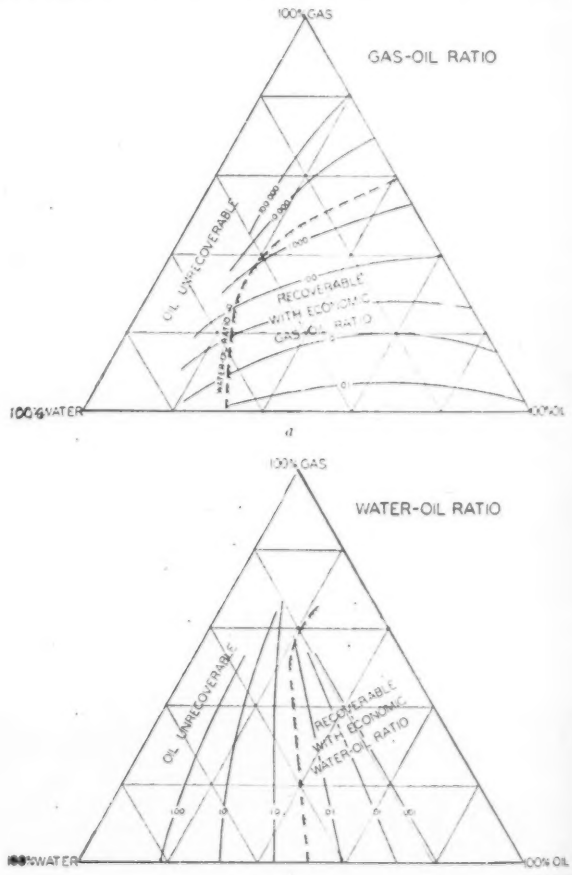
Fig. 1 (below). Composite curve showing variation of relative permeability with liquid saturation in unconsolidated sands

(From Wyckoff and Botset[4])

Fig. 2 (right). Variation of gas-oil and water-oil ratios with saturation of gas, oil, and water in unconsolidated sands

(From data of Leverett and Lewis[8])





The gas-oil ratios and water-oil ratios calculated from the data cited heretofore were inserted in the triangular diagrams alongside the point representing the condition of saturation existing when these ratios were observed in the flowing stream. The gas-oil ratios and water-oil ratios were then contoured by connecting points of equal value. Considerable irregularity in the values was noted, due in part to the use of oils of differing viscosity, and the contour lines are generalized and approximate.

Both diagrams show that no oil flowed when the oil saturation was below about 15 per cent. This illustrates the well-known fact that the oil saturation cannot be reduced below a certain point by any mechanical means. In Fig. 2*a*, as the gas saturation increases (i.e., going upward) the gas-oil ratio increases geometrically. This is in line with other published data showing the change in gas-oil ratio with saturation (Krutter's[7] Figs. 3 and 4). With increasing water saturation for any given oil saturation (following a line downward and to the left) the gas-oil ratio decreases. With a sand having saturation of 70 per cent gas and 30 per cent oil (no water) the gas-oil ratio is about 10,000, while with a saturation of 30 per cent oil, 20 per cent gas, and 50 per cent water the gas-oil ratio is about 5. At the former saturation gas-drive operation would be uneconomical, but at the latter would be successful, although the oil saturation in each case is the same.

The presence of water not only makes it economically possible to recover the oil, but it makes possible the ultimate recovery of a larger proportion of the oil originally in the reservoir. Krutter (Fig. 15 of ref. 7) shows that by gas drive the greatest recovery of oil, expressed in terms of percentage of oil originally in the sand, occurs when the water content is about 30 per cent.

The approximate range of saturations that may be economically driven with gas can be arrived at as follows. If the limiting economic gas-oil ratio is about 3000 vol. of gas per volume of oil (17,000 cu. ft. per bbl.), then, according to the data shown in Fig. 2*a*, sands containing more than 40 per cent oil with no water, or more than 20 per cent oil with 40 per cent water, can be driven with gas. At high water saturations the water-oil ratio becomes large. Since a water-oil ratio of about 10 vol. of water per volume of oil may be considered an economic limit, water saturations of the order of 70 per cent form a limit in this direction. Combining the 3000 gas-oil ratio line with the 10 water-oil line gives the limiting range of saturations for gas-drive operations as estimated from these data.

The water-oil ratio in a water flood (Fig. 2b) is controlled similarly by the relative amounts of water and oil in the sand. For an oil saturation of 45 per cent and a water saturation of 55, the water-oil ratio is 1; that is, the flowing stream will consist of equal parts of oil and water. If the oil and water saturations are such that more water than oil will flow, it appears that the concentration of oil to form a bank ahead of the flood cannot occur. The "initial" stage of displacement will be absent.

Critical oil and water saturations. The foregoing reasoning, based on the published experimental data referred to above, indicates that some depleted oil sands may be economically flooded by water drive, and that other sands may not be flooded by water drive but may be worked effectively by gas drive, depending on the oil and water saturations of the sands. Furthermore, a very small difference in the relative saturation of oil and water in a critical range may determine whether the initial stage of water-flooding will occur, and therefore whether water may be used economically as a flooding medium.

For example, if a sand is more permeable to water than to oil before flooding, the initial or bank stage cannot occur, and the subordinate stage, although it may recover appreciable quantities of oil, will be uneconomical. The existence of a critical oil and water saturation may be inferred from the data of Leverett and Lewis, and it appears to be in the neighborhood of equal quantities of oil and water. Its exact value cannot be determined from their work, and probably it is different in different sands; also, undoubtedly it will vary somewhat with several other factors.

The viscosity of the oil enters directly into the equation determining the fraction of oil in the flowing stream and is important therefore in determining the critical saturations. It appears to be of much less importance than the oil-and-water saturations, which govern the effective permeability geometrically. Thus doubling the viscosity of the oil should double the water-oil ratio, while a decrease in oil saturation of only about 5 per cent would also double the water-oil ratio.

Doubtless the effect of capillary pressure[10] is also important. These pressures depend on the relationships of the interfacial tensions of the three fluids and the solid phase and are affected by the original distribution of the phase wetting the solids. The capillary forces unquestionably are important in determining the most advantageous rate of advance of the water. If the removal of oil is due to a combination of the effects of hydraulic and capillary forces, the optimum rate is that at which the resultant of the forces brings about the greatest recovery of oil. The question of whether oil or water predominantly wets the sand at the start of the flood cannot be neglected, certainly. For any given saturation of oil and water, it appears likely that the effective permeability to oil may be different if the sand is oil wet or water wet. It is even possible that at low pressure differentials the permeability of the wetting phase is increased while at high pressure differentials the permeability of the non-wetting phase is increased.

If the water saturation is so low that the oil of necessity wets a very large proportion of the solid surfaces, the residual oil left after the water flood may be comparatively high. Hence, too low a water saturation, especially if accompanied by a high gas saturation, may make water-flooding impracticable, as well as too high a water saturation.

The porosity, dry permeability, and pore-size distribution undoubtedly affect the relative permeabilities of a sand to oil or water. Their effect is closely associated with the capillary phenomena mentioned above. The results of tests on an unconsolidated sand cannot be applied quantitatively to a highly consolidated sand like Pennsylvania's.

There seems to be no reason why all these conditions, which determine the critical relative permeability of a sand to oil and water, cannot be investigated in the laboratory, and routine tests developed to determine the possibility of recovering oil by water-flooding. It seems probable that the effects of viscosity and capillary phenomena are of a much smaller order of magnitude than the effects of actual percentage of pore space occupied by oil and water, at least in a normal water-wet sand.

In secondary oil recovery by gas drive, the formation of the initial or bank stage is less important than with water drive. Consequently, it may be that there is no critical range of saturation wherein a small variation will make the difference between success and failure. If gas is injected into a sand that has a gas saturation so high that mostly gas will flow, the gas-oil ratios will be high and the operation will be uneconomical. The gas-liquid ratio flowing depends on the relative amounts of gas and liquid in the sand, and it makes little difference whether the liquid in the sand be water or oil, at least for total liquid saturations greater than 40 per cent. Thus, if the liquid consists of equal quantities of water and oil, approximately equal quantities of water and oil will be moved through the sand. If the sand contained the same amount of oil, but no water, it would contain only one half as much liquid, and the gas-liquid ratio would be greatly increased. Thus, for a given amount of oil

in a sand, the amount of oil recovered by gas drive will be affected by the amount of water in the sand.

Application to field operations. Even if the exact values of the critical saturations described could be determined in the laboratory for any sand, the problem of obtaining representative core samples from a prospective field of operations would remain. Much progress in the taking of cores has been made recently by the use of oil-base muds and pressure core barrels. It has become possible to estimate the connate water of a sand with a very fair degree of accuracy by means of electric logs. Fortunately, the low pressures in most fields undergoing secondary recovery facilitate the recovery of representative cores. In testing a field for secondary-recovery operations, it might be well worth while to take a core in the sand using regular mud and then immediately sidetrack the hole and take another using oil-base mud. One core would then give reliable oil saturations and the other reliable water saturations. In the Bradford field reliable cores are obtained regularly, probably because of the low horizontal and vertical permeability of the sand, which prevents flushing of the sand ahead of the bit. In looser sands, the problem is a good deal more difficult.

Although this discussion admittedly is speculative, and is based largely on laboratory work on unconsolidated sands, which cannot be applied quantitatively to field operations, there is some evidence that critical water saturations exist and are important.

In the Bradford field of Pennsylvania the average oil saturation is 40 per cent, and the average water saturation 30 per cent. Gas drives in this field have caused a much smaller and slower recovery of oil than have water drives. The inefficiency of gas drives was due in part to the low permeability, which averages 10 millidarcys. Water drives have been notably successful in this pool. In certain sections of the pool, however, the water saturation is higher than the average. It has been found that if the water saturation exceeds about 40 per cent, no "bank" is formed, and oil is produced at uneconomically high water-oil ratios. In one district, where the water saturation was about 60 and the oil saturation about 30 per cent, the initial water-oil ratio on flooding was about twenty to one.

In the Venango fields of Pennsylvania the normal oil saturation ranges between 25 and 35 per cent, and the water saturation between 40 and 60 per cent. In spite of very numerous attempts, no water-flood operation has been successful in these sands. In almost every case the water came through bringing very small and uneconomical quantities of oil. Gas driving, on the other hand, has been quite successful. Recoveries as high as 100 bbl. per acre-foot have been obtained, and 50 bbl. per acre-foot is obtained frequently. This amounts to a reduction in saturation of 5 to 8 per cent of the pore volume, which is remarkable considering the low initial oil saturations.

Districts in the Mid-Continent where water flooding failed because of high water saturations in the sand are known, and are mentioned by Horner.[11]

At other places, water-flooding has been attempted on the basis of an oil content, expressed in barrels per acre-foot, much higher than normal for the Bradford field. When expressed as saturation in percentage of pore volume, however, the oil saturations were lower than at Bradford, because of the high porosity of the sand, and the floods were failures.

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☆ ☆ ☆

Application of Job Design to Petroleum Production Operations

The purposes of this paper are to explain what "job design" is, how it is done, and to present examples of its application to surface and subsurface maintenance and pumping activities of petroleum production. Job design is a phase of engineering dealing primarily with the effective utilization of labor on the job. To the best of my knowledge the first application of this technique to petroleum production was made in the fall of 1939 at the invitation of the Phillips Petroleum Company.

Job design is also termed time and motion study, motion economy, and work simplification. The writer prefers the term job design because it seems to be the most descriptive of the several terms. While job design is new to petroleum production, it has been in use over a half century and is now accepted as an important tool for cost reduction in many industries.

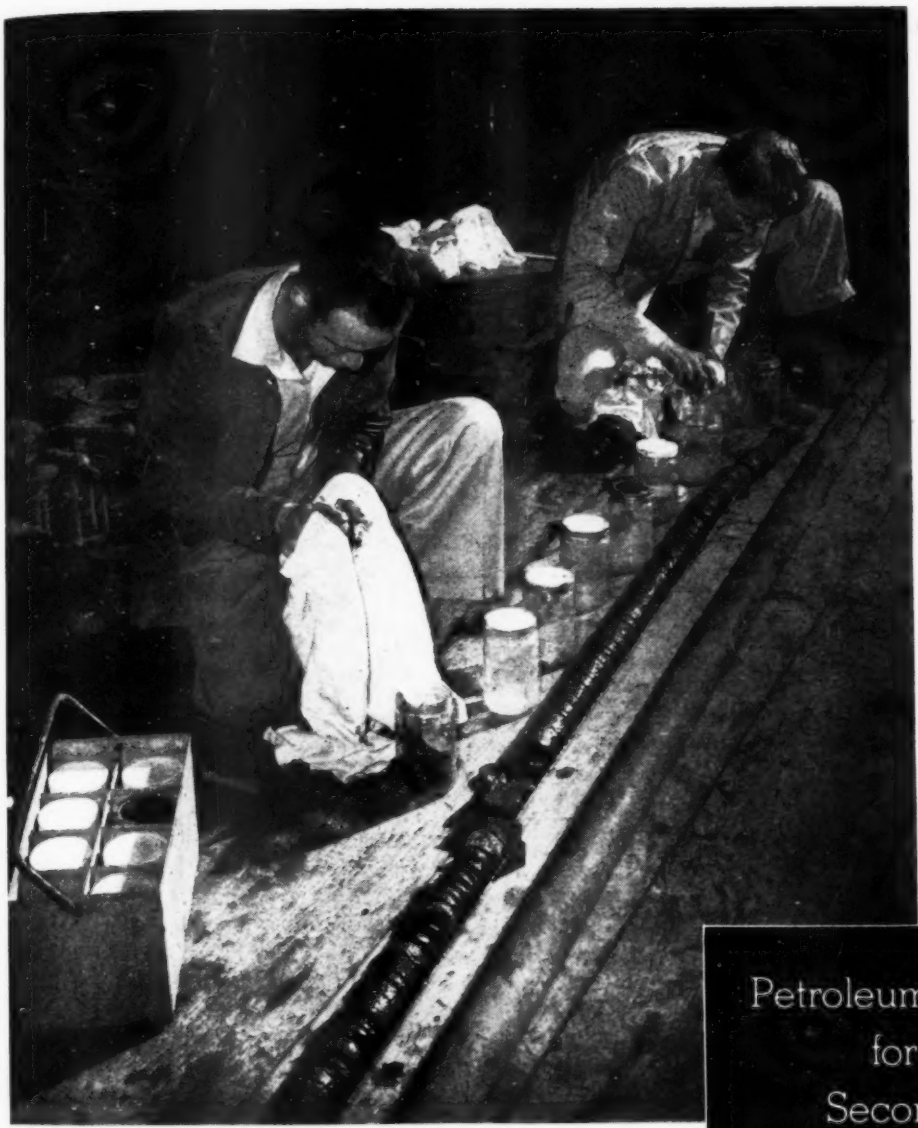
Since labor cost is one of the largest, if not the largest, items of cost in petroleum production, an increase in the efficiency of labor utilization can result in important competitive advantage. In private industry three demands must be met. These are the demands of the owners for dividends, the consumer for better products at lower prices, and the employee for higher wages for shorter hours. These demands must be met in a competitive enterprise.

What is job design? To design is to protect and evaluate ideas. Job design consists of breaking the work of the job into definable and measurable elements, analyzing these elements for effectiveness in doing work and then reconstructing the job, using only effective elements in proper sequence so that the job can be performed in the shortest time with the least effort.

Restated, job design consists of determining the essentials of the job and selecting effective elements of work for the accomplishment of the essentials. Methods are improved by:

1. **Eliminating unnecessary elements of work.**
2. **Substituting effective for ineffective elements of work.**
3. **The elimination of periods of enforced idleness.**

—From a paper by H. G. Thuesen, Department of Industrial Engineering, Oklahoma A. and M. College, at A.P.I. meeting May, 1944, Tulsa.



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Factors Influencing Well Spacing in Condensate Fields*

By E. O. BENNETT
Consulting Engineer

SPACING of wells for condensate production rarely follows any of the patterns generally used in gas or oil fields. Each condensate pool has certain characteristics which, together with the development that has taken place up to the time additional wells are to be drilled, will control the location of the new wells. We generally think of spacing as defining the number of acres per well or the distance between wells. The pattern of spacing indicates whether the wells are drilled directly offsetting each other, diagonally or on some other regular pattern. The term spacing as used in this summary refers only to the location of wells with respect to each other or to the structure in a general way as the ultimate allocation of acres per well may vary considerably and the pattern may not be regular or geometrically symmetrical in any way.

The initial spacing problems faced in a condensate pool have to do with those exploratory wells drilled following the completion of the discovery well. These exploratory wells are drilled and spaced with the following objectives in mind:

1. To determine the upper and lower limits of condensate production. The upper limit may be a fault, a lensing out of the pay or extreme diminution of porosity and permeability. The lower limit may be determined by water, oil, or another fault and rarely by the lensing out of the effective pay.

2. To determine the size of the condensate pool. It is extremely important that the size of the condensate pool be determined as early in its life as possible. The size will control to a certain extent the spacing of additional wells, will indicate the desirability of unitization, and whether or not a cycling plant should be installed. The size will also determine the reserves in place and permit the proper size plant to be designed. Experience indicates that wide spacing proves most economical on the average.

3. To determine essential data on the reservoir such as net pay thickness, porosity, permeability, and interstitial water content as well as to provide sampling points for the determination of bottom hole pressure, dew point, composition, etc., either from bottom-hole separator samples so that the character of reservoir fluids may be established. These data together with those obtained in No. 2 above can only be obtained by the drilling of wells. Samples should be taken from all the original exploratory wells drilled. In some cases exploratory wells may be drilled only for the above purposes, within the proven limits of the field and such wells are so spaced:

4. To provide suitable production or injection wells that will fit into the final pattern.

5. To define the upper and lower limits of the liquid (oil) that may exist in the same pay zone. Reservoir formation and fluid data should be obtained in those wells that encounter liquid as well as in the exploratory wells drilled for other reasons.

Upon completion of the exploratory wells, consideration must be given to the spacing of additional producing or input wells as may be required to meet the market demand for liquid plant products or gas. The dew points determined together with the compositions might at first glance indicate to the operator either that the gas exists at the dew point in the reservoir and therefore liquid should exist in the same formation or that the gas is not subject to retrograde condensation and therefore no liquid should be encountered at the base of the sand. Neither conclusion should be considered final until the drill proves the existence or absence of oil. The discovery of a commercial oil deposit at the lower edges or bottom of the condensate reservoir introduces spacing problems within the oil zone and in the offsetting condensate reservoir that are complicated and difficult to solve. Existing cases definitely indicate that serious consideration to early studies for unitizing of such pools should be given.

Varying conditions such as the presence of or absence of oil, the quality or character of the reservoir gaseous fluid, and whether competitive or cooperative (unitization) operations will be followed have a considerable bearing on the spacing of wells in condensate pools. The discussion of spacing is therefore separated under five general headings below, which will cover most condensate pools.

1. Condensate pool with no liquid—not cycled. (a) Competitive operation introduces so many factors for pools under this heading that a discussion of spacing would prove academic and is therefore not attempted in the general. The specific case would require individual study.

(b) Cooperative or unitized operation. The smaller condensate pools do not justify cycling; the size and cost is not sufficient to permit increased recovery to pay for the installation. The spacing problem then resolves itself in the location of wells which in number

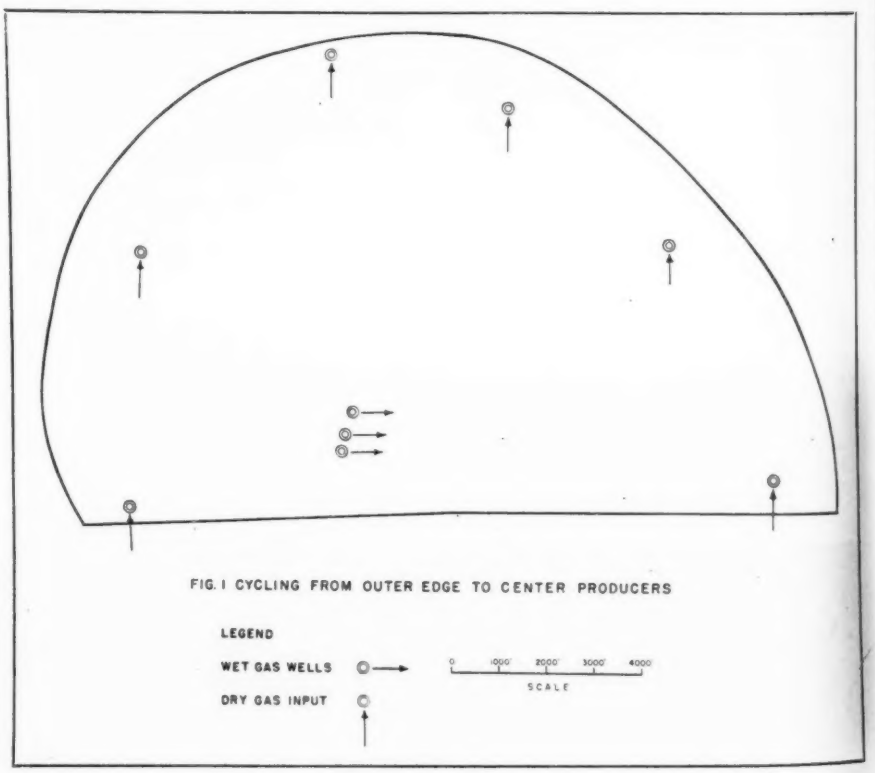
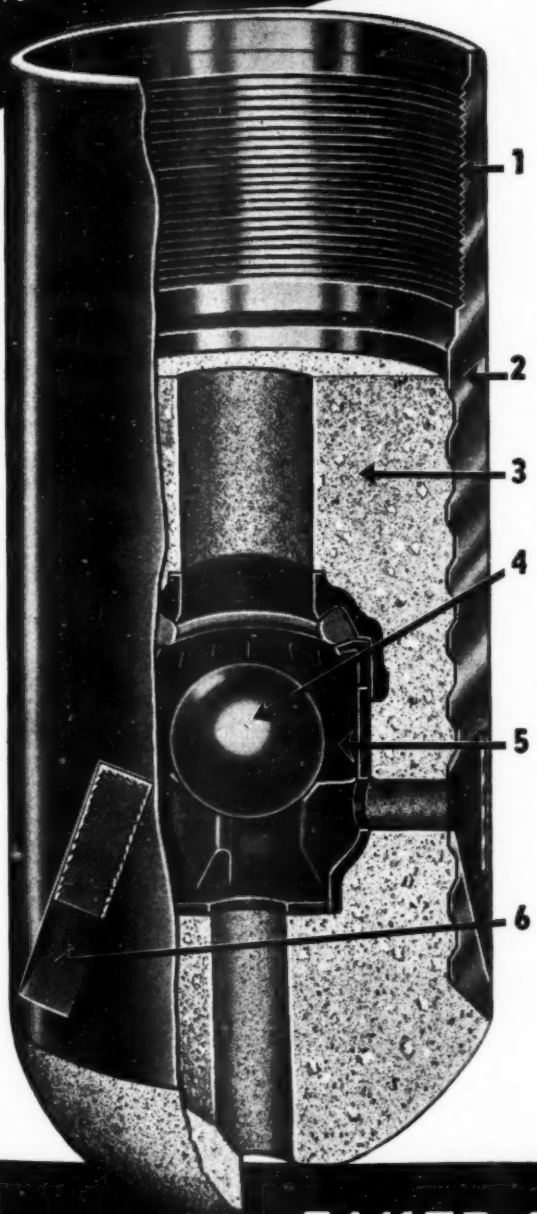


FIG. 1 CYCLING FROM OUTER EDGE TO CENTER PRODUCERS

*Presented before American Petroleum Institute, Southwestern District Division of Production, Houston, Texas, June 13-14, 1944.

What's in Your Knowledge Box?



If you are connected with the drilling or production end of the oil business, there are certain facts about this important piece of equipment which should be in that portable "knowledge box" you carry around. First-time cementing success often depends upon the use of this unit, and it is *always* your best bet for a good, permanent cement job.

All set? Get your pencil and open up that "knowledge box." You score 80% by correctly answering 6 questions; 85% for 7 answers; 90% for 8; 95% for 9; 100% for 10 right answers. Correct answers are at the bottom of the page, but check *all* questions before you look.

1. This device is a: (a) Core Barrel ☐ (b) Baker Model K Cement Retainer ☐ (c) Baker Cement Wash-Down Whirler Float Shoe ☐ (d) Cement Plug ☐

2. Arrow 1 indicates threads for attaching to: (a) Drill Pipe ☐ (b) Any specified casing ☐ (c) Bottom of junk basket ☐ (d) Any perforated liner ☐

3. Arrow 2 points to the: (a) Seamless steel shoe ☐ (b) Aluminum housing ☐ (c) Core barrel body ☐ (d) Case of magnesium alloy ☐

4. The purpose of this Bakelite ball, Arrow 4, is to: (a) Seal off when pump pressure is applied ☐ (b) Disintegrate when contacted by cement slurry ☐ (c) Prevent reverse movement of slurry ☐ (d) Prevent movement of slurry out of bottom hole ☐

5. The Valve Cage (Arrow 5) is made of: (a) Alloy steel ☐ (b) Vulcanized rubber ☐ (c) Aviation aluminum ☐ (d) Plastic formed from synthetic resins ☐

6. This opening (5) insures: (a) downward whirling of cement slurry ☐ (b) Easy entry of oil ☐ (c) Large volume of reverse circulation ☐ (d) Speed in picking up junk ☐

7. Cement is used here (arrow 3) because: (a) It resists abrasion when oil enters tubing ☐ (b) It has great strength, but is easily drilled out and circulated away ☐ (c) It absorbs gas, thus reducing the gas/oil ratio ☐ (d) It is harder than cast iron ☐

8. This complete unit is often helpful in: (a) Taking better cores ☐ (b) Directional drilling ☐ (c) Removing bridges while running casing in the hole ☐ (d) Locating water zones ☐

9. For successful "first-time" cementing jobs, this unit should be used: (a) Only in wells over 10,000 feet deep ☐ (b) On casing up to 5-inch O.D. ☐ (c) Where no water trouble is anticipated ☐ (d) For cementing practically every string of casing ☐

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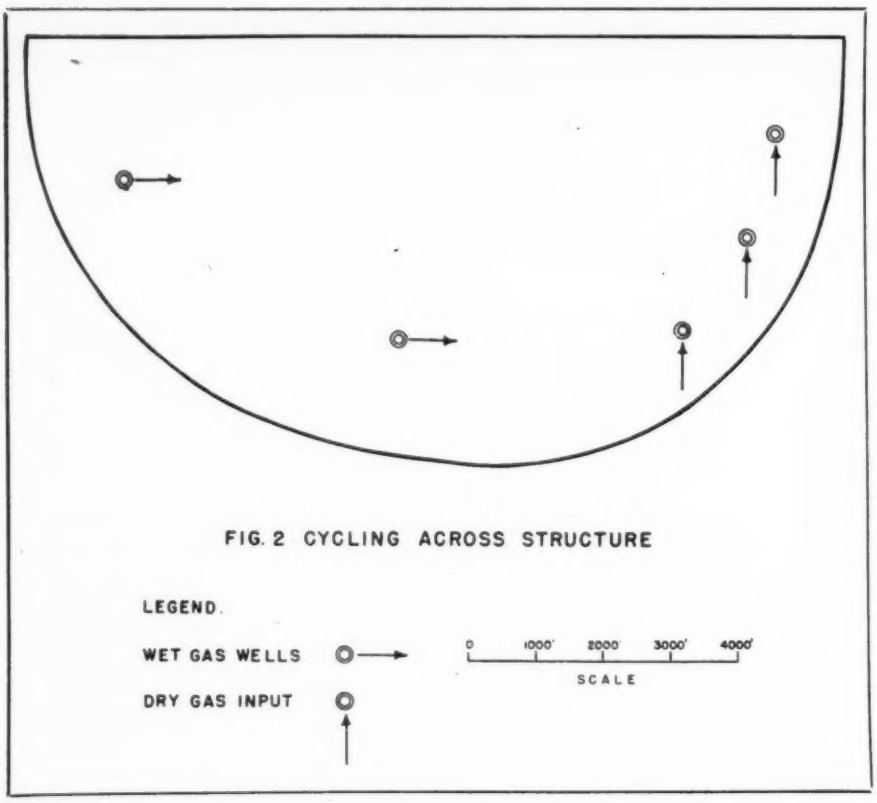

FIG. 2 CYCLING ACROSS STRUCTURE

might be controlled by the capacity of the wells to produce, availability of a market for the gas, etc. The pattern on which these wells would be drilled would in turn be controlled by the availability of reserves taking into consideration the character and distribution of the reservoir formation and the expectancy of water encroachment or expansion drive.

2. Condensate pools with no liquid—cycled. (a) Competitive operation of condensate pools with cycling exists. Spacing in these areas followed no general rule.

The spacing of wells in the smaller pools becomes so closely related to economics that no general discussion seems appropriate.

(b) Cooperative operation with cycling may be in the form of more than one unitized groups operating in the same pool.

In the fully unitized and simpler type of structure producing wells would usually be located at the top or along one side of the structure. The input wells through which the dry gas is returned are in turn located at the edge of the structure or on the sides away or across from the producers. This general pattern allows for the maximum sweep out or invasion of the condensate containing formations by the dry gas. The presence of faults or formation pinch outs would modify the producing structure and therefore the spacing of the wells. A typical example of cycling toward the center or top of the structure is shown in Fig. 1. Cycling across structure is shown in Fig. 2. It will be noted that the wells are spaced with reference to capacity and invasion pattern. Full utilization of the exploratory wells together with a few additionally drilled wells may result in a somewhat mixed spacing or pattern as shown in Fig. 3.

The presence of two or more cooperative cycling groups in the same pool would modify the spacing in accordance with the size and distribution of pay and therefore comparative estimated reserves, plant sizes and other factors. Trade outs of injection wells along lines similar to those made in repressuring of oil fields are possible, and may result in either a concentration of injection wells in one area with a scattering of the producing wells or the reversed pattern.

Edge or watered wells near the edge of condensate can be utilized for cycling. Dry gas has been returned successfully to watered oil sand or to edge wells in oil fields. There should be no reason why this procedure will not be highly satisfactory in the spacing of input wells in condensate pools. The utilization of edge wells drilled into water is now being tested in condensate pools. The results will be of considerable interest as, if successful, greater invasion can be secured and the wide spacing recommended during exploratory drilling to determine pool limits will not be penalized as many of the edge wells can be fully salvaged as input wells.

3. Condensate fields with liquid—not cycled. The liquid or oil in the condensate reservoir may be sufficient to justify its own development program. The oil is considered as commercial for the purpose of the following discussions.

(a) Competitive operation. The spacing of condensate wells in this type of field is controlled in part by the spacing of the oil wells. A concentration of condensate wells would result along the upper edge of the liquid saturation as a result of offset spacing to the oil wells when the liquid is down dip. In the case where the liquid underlies condensate

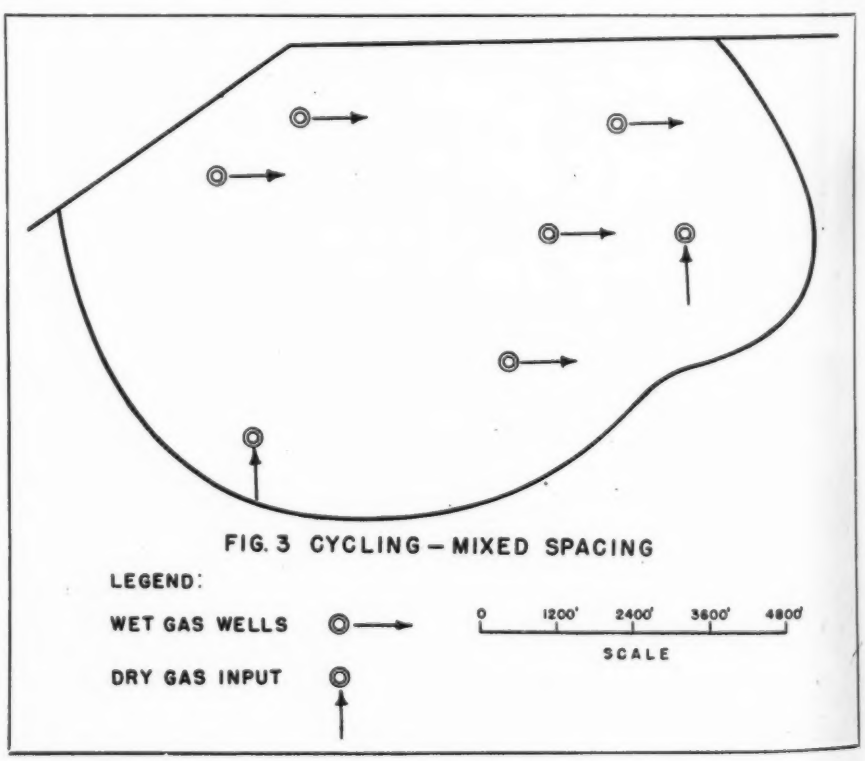

FIG. 3 CYCLING—MIXED SPACING

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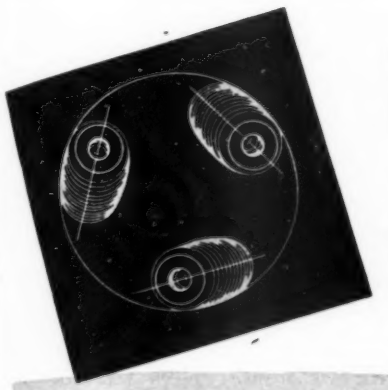

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TYPE 4 CUTTER is used for reaming and bit stabilization in soft or sticky formations. It can also be used for rock bit stabilization in hard formations.

TYPE 6 CUTTER has flattened spiral flutes that impart a crushing action with a slight amount of cutting. It is used mainly for bit stabilization in extremely hard formations where only a slight amount of cutting action is desired.

over a considerable area, the two types of oil and gas production are superimposed and spacing problems would generally be greater in number and more complex.

The number and spacing of condensate wells drilled within the condensate area would then correspond to case 1-a with necessary modifications.

(b) Cooperative operation. The oil operators may or may not be cooperating or unitized with the condensate group. Wells would be spaced in the condensate pool following the general procedure as outlined in 4-b when unitized and as outlined in 1-b when competing. Possible variations in spacing could only be suggested for the particular case.

4. Condensate fields with liquid —cycled. (a) Competitive operations. Condensate fields in this class may present no spacing problem or some of the most interesting spacing layouts due to the additional factors introduced. Competitive operation may exist in the oil zone and in the condensate zone. All operators may not be cycling. If cycled, one or more plants may be operated. One or more operators may be selling gas from the separator. Spacing of wells is therefore greatly influenced by offset situations as well as by the normal condensate features.

(b) Cooperative operation. A fully unitized operation of the condensate would indicate a reversal of the spacing discussed under 2-a where no commercial oil co-existed with the condensate. Input wells would normally be located at the top of the structure. Producing wells would be located at the oil-gas contact or slightly above same. This situation is shown in Fig. 4. Upper edge oil wells could be dually completed for condensate and oil production or converted to condensate producers as they became gassy.

5. Limestone condensate reservoirs. These may present relatively different spacing problems. Spacing in limestone should take into consideration: (a) acre feet of available pay, (b) maintaining availability of the pay, and (c) the practicability of cycling. Massive limestone or dolomite with small pores and low permeability is usually commercial only when fractured. The degree of fracturing and the degree of intercommunication through the saturated limestone established by the fracturing controls the amount of available pay. Maintaining this pay as available may require continued reduction in pressure so the condensate in the tighter portions of the limestone will continue to expand into the more permeable streaks and thus be made available. Cycling would possibly not be beneficial in this type of pay. However, initial cycling followed by expansion later may prove economical. These and related problems make spacing of condensate wells in fractured limestone a problem somewhat different to the spacing problem in sandstone reservoirs.

Spacing problems in intergranular limestone reservoirs may be exactly similar to those in sandstone reservoirs. Fitting and Bulnes* have pointed out that intergranular limestones may not behave like sands in the lower ranges of porosity and permeability.

The final spacing and pattern would be controlled in part by the exploratory wells already available and aid in locating additional wells may be obtained by electrolytic or potentiometric model surveys, by theoretical studies, or by inspection taking into consideration the capacity desired. The desired production or input capacity cannot be met in tight formation in retrograde condensate pools by a minimum number of wells. The condensate will drop out in the formation reducing its effective permeability to gas. The effect has been large enough to reduce gas flow, as the wells are opened up, to a fraction of the flow on smaller chokes and higher pressures.

Spacing problems in condensate production have to date varied from field to field. No general spacing rules can be set up as spacing is an integral part of the program and not subject to separate economic rules.

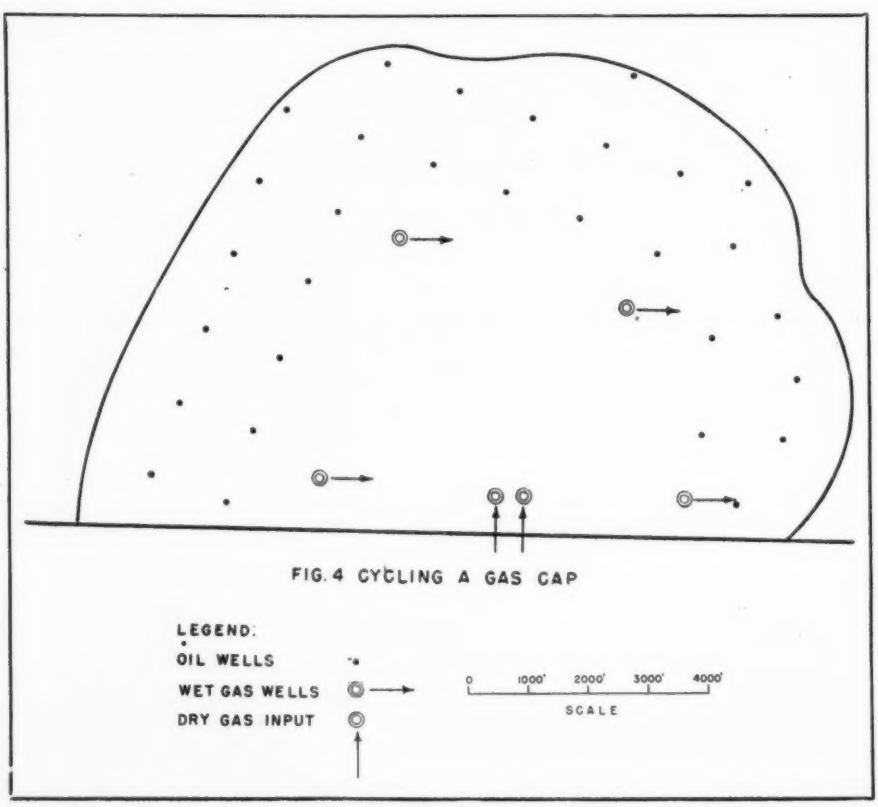

FIG. 4 CYCLING A GAS CAP

*"An Introductory Discussion of the Reservoir Performance of Limestone Reservoirs," R. U. Fitting, Jr. and A. C. Bulnes, A.I.M.E., Houston, Texas, May 8-9, 1944.

☆ ☆ ☆

A Method of Handling Salt Water Disposal

Salt water disposal has become one of the important integral parts of oil and gas production. The evolution of salt water disposal is traced from the early beginnings of oil production in the Mid-Continent to the present date.

Designs of various types of salt water disposal systems now in use are briefly outlined. Statistical data covering the partial operations of eight producing companies is listed.

The complete report covers an initial investment of $4,204,965.86 for 256 systems, an operating cost of $1,213,253.05 for 86 systems that include 387.58 miles of pipe line made up of 151.31 miles of cement asbestos pipe, 27.83 miles of cement asbestos and cement lined pipe, 44.38 miles of cement lined and steel pipe, 7.30 miles of cement asbestos and fiber pipe, 18.77 miles of fiber pipe, 78.23 miles of cement asbestos and steel pipe, 31.31 miles of steel pipe, 25.75 miles of cement asbestos, fiber, and cement lined steel pipe, 2.2 miles of cement lined steel pipe, and steel and .5 miles of cement asbestos, cement lined steel and steel pipe.

The statistical data also reveal the cost per barrel and the rate of injection for the various types of treatment, and complete articles of agreement for the salt water disposal association.

—Abstract of paper by H. H. Elliston and W. B. Davis, A.P.I. meeting, May 25, 1944, Tulsa, Oklahoma.

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Operation and Maintenance of a Crude Oil Pipe Line Without Spare Units*

By JOHN G. NORTON, Chief Mechanical Engineer
Magnolia Pipe Line Company

THIS paper will cover only the most important features that contribute to the successful operation and maintenance of the line under discussion. It is hoped that in the "Discussion" and "Quiz Period," following the reading of this paper, that the detailed methods of maintenance and operation will be fully discussed so that all of us will benefit from the ideas and suggestions brought forth. The following line data and station equipment is given in order to present a clear understanding of the problems involved in the operation and maintenance of this 10-in. line.

Line data. The line extends from Patoka, Illinois, to Lima, Ohio, a distance of 300.93 miles. The elevation at Patoka station is 480 ft. and at Lima, Ohio, terminal 865 ft. The pipe is 10¾ in. O. D. by ¼ in. in wall thickness. The stations are hydraulically balanced. Patoka station, hereinafter called No. 1, has sufficient storage capacity for our operating conditions. At the centrally located station on the line, called No. 5, we have one 80,000-bbl. tank. These two stations are the only stations that have tanks. The Lima, Ohio, terminal has ample storage to meet the line requirements. Our district office and the dispatchers are located at Danville, Indiana, near the center of the line.

The company has its own telephone system; however, it is not located on the pipe line right-of-way, but laterals in from commercial system lines. We have, at most stations, another connection to a commercial system for emergencies.

Equipment. No. 1 Station: Two 13¼-in. by 17½-in., 415-hp. at 360 r.p.m., 5-cylinder, 4-cycle, solid-injection diesel engines. Each engine is direct connected through "step-up" gears to one 6-in., 4-stage, 3200 r.p.m., centrifugal pump. Fortunately just prior to our country's entrance into the war, we were able to make up a unit that gives us a spare unit at this station, namely, a 13¼-in. by 17½-in., 375-hp. at 327 r.p.m, 5-cylinder, 4-cycle, solid-injection engine direct connected through a "step-up" gear to a 6-in., 4-stage, 3600-r.p.m. centrifugal pump.

Stations 2, 3, and 4 have the same make of engines and pumps as Station No. 1, but have only 2 units each.

Stations 5 to 8 inclusive have the following equipment in each station: Two 12½-in. by 13-in., 405-hp. at 450 r.p.m., 6-cylinder, 4-cycle, solid-injection diesel engines. Each engine is direct connected through "step-up" gears, to one 8-in., 4-stage, 2900-r.p.m., centrifugal pump. There are no spare units in any of these stations. Each station, 1 to 8 inclusive, has a 15-kw. d-c, generator direct connected to a 23-hp. diesel engine, which is used for lights, etc., when the main units are out of service.

All the engines on this system use centrifuged crude from the line for fuel and all engines are equipped with the Bosch fuel injection system. The small auxiliary engines also use centrifuged crude as fuel. The engines are equipped with hydraulic governors of the constant speed regulation type, manually operated. The engine circulating water system is the enclosed type, and cooling is maintained by the use of suction type single pass heat exchangers. The heating for the station is obtained from exhaust heat boilers, which supply steam for suspended type unit heaters.

The line and engines are equipped with all the necessary safety and emergency apparatus. Each engine is equipped with pyrometers.

The main line centrifugal pumps operate in series. Each pump has a shut off pressure of over 400 lb. per sq. in. Each pump is equipped with mechanical seals. The centrifugal circulating water pumps are chain belt driven from the engine extension shaft, and each pump has a capacity large enough to cool both engines in each station. Each engine has a surge tank, which is double connected making each cooling system available for double duty if the occasion arises. Each engine has a chain belt driven 15-kw. d-c. generator for station lighting and other auxiliary uses.

The "step-up" gears, or speed increasers, on the system are from three different manufacturers. Last year we installed at Station No. 5 in a separate building a booster unit consisting of a 2-stage centrifugal pump good for 1880 bbl. per hr. at 100-lb. pressure. This pump is V-belted to a 96-hp. engine that uses crude as fuel.

Design and demand. This line was designed and constructed in 1939 for 37,000 bbl. of crude per day at 650 lb. gauge pressure to meet our required demands. When the line was designed the equipment selected could very easily meet all conditions of transportation with a very low load factor; therefore, we did not see any necessity in installing a spare unit in each station.

The source of the crude supply from 1939 to 1941 was principally from the Salem, Illinois, field, but since that time the major portion of the line's crude supply has come from Mid-Continent areas. The crude is a mixture of many crudes and runs about 0.830 sp. gr. and has a viscosity of 60 S.U.S. at 60°F.

Since 1941 this line has been stepped up in capacity to meet both the war effort and refinery demands and for the past 3 years has averaged a minimum of 41,500 bbl. per day at line pressures from 700 to 750 lb. per sq. in.

Operation and dispatching. The successful operation of any line and station, designed for series operation without storage at the stations, depends absolutely on the control and supervision maintained by the dispatchers.

It readily can be seen from the information previously furnished in the general outline, that this line is very flexible, and with an 8-station set-up, displacements of approximately 28,500, 31,000, 36,000, 42,000, and 45,000 bbl. per day can be made with maximum pressures used with various unit and station combinations. Capacities ranging between those just mentioned can be obtained at other pressure points.

Our dispatchers operate each and every pump, engine, and station on the differential pressure and horsepower limit basis from predetermined rules and formulae. Actual line flow, differential pressures, and engine r.p.m. are checked each hour with the formulae and instructions. Each station and its units are controlled so that no unit is overloaded or abused. In other words, we have set the maximum load limit for each unit or units in order to obtain the best throughput for the line without causing any mechanical failures from poor operation and supervision. On this particular type of line design, the dispatchers must be very alert and efficient, if each station in the series chain is to do its whole part in obtaining the maximum throughput for the working pressures used. Our dispatchers on this line have been given the necessary authority, without interference, for the successful operation of the system and are responsible for its entire operation in the movement of crude, and to date its performance reflects their good supervision.

Maintaining line efficiency by a planned scraper program. In order to get the maximum throughput to meet our refinery and terminal demands, a scrapper program has been worked out.

We have recording thermometers at three points on this system, namely, at stations No. 1, No. 5, and the Lima terminal. With the use of the heat exchangers on the suction to the pumps at each station, a 1°F. drop is maintained from Patoka, Illinois, to Lima, Ohio. The weather records show that the average winter temperature in the Central

*Presented before The American Society of Mechanical Engineers, Oil and Gas Power Division, Tulsa, Oklahoma, May 8-10, 1944.

Illinois area is much higher than at the terminus of the line at Lima, Ohio.

We transport a mixture of crude that contains a high percentage of paraffin and wax, and because we have but one tank along the line, which is at Station No. 5, we are compelled in cold months to operate scrapers frequently.

During the months of June, July, August, and September, it is only necessary to pass a scraper through the line the first and last month of this period. In the three coldest months January, February, and March, the temperature of the crude in the line averages from 38° to 42° F. and during this period scrapers are run approximately once a week from stations No. 1 to 5 and twice a week from station No. 5 to the Lima terminal. The capacity drop in bbls. per day is approximately twice as much from station No. 5 to the terminal as from station No. 1 to 5.

The scraper program is so arranged that when the scraper from station No. 1 arrives at station No. 5, the capacity drop from stations No. 5 to the terminal is at about one half of its maximum capacity drop.

A daily continuous graph is made by the district superintendent and the chief dispatcher showing the actual line operating capacity condition and from this graph they know exactly when to put the scrapers in the line.

Scrapers are put in the line after the capacity has dropped approximately 5 per cent from the maximum throughput of a clean line for that particular time of the year.

During the coldest months of the year the line from stations Nos. 1 to 5 average about 150 to 200 bbl. per day drop in capacity. The line from station No. 5 to the terminal averages for this same period 200 to 325 bbl. per day drop in capacity. It requires about four days and five hours for a scraper to travel the 300 miles of line. Each station prior to the arrival of a scraper is shut down and the valve to the station suction header, the heat exchangers, and the pumps, is closed so that no paraffin, etc., will get into the heat exchangers and pumps. Scrapers are taken out at every second station and another one is already in the outgoing scraper trap to be started out as soon as the incoming scraper arrives; this is done to save shut down time. The scrapers are kept in A-1 mechanical condition and always travel at their rated speed.

To compensate for some of the capacity drop between station No. 5 to the terminal, we have installed a suction pump driven by a diesel engine that gives the No. 1 main pump 80 to 100 lb. suction pressure. While this suction unit is in operation we have a station discharge pressure of 800 lb. and we evenly distribute this 100-lb. boost between stations Nos. 5, 6, and 7.

Operating and maintenance personnel. Each station has a chief engineer, three engineers, and a yardman.

The engineer's duties keep him inside the station at all times. All outside work is done by the yardman or extra men.

We have one district machinist and two other machinists under his supervision, each of these two machinists cares for the maintenance of four stations. Extra help is furnished the machinists from the connection gang. The machinists supervise all the repair and inspection work.

The station engineers, beside their routine duties, do the exhaust and inlet valve grinding and minor maintenance.

The chief engineer, as a rule, takes care of all valve and tappet adjustments, and spray valve and fuel pump testing. This class of work requires special experience and good judgment.

All major inspections, maintenance and repairs pertaining to connecting rods, bearings, pistons, rings, crankshaft inspections, and major adjustments are performed under the supervision of the district machinist or machinists. They likewise take care of the maintenance of the pumps, speed increasers, and all auxiliary equipment. Close cooperation is practiced between the chief engineer and the machinists and all work procedures are thoroughly planned before any work is done.

All regular maintenance and inspections are carried out on a planned schedule at a set time. The work is so arranged that we try to coordinate several jobs at various stations so that the dispatchers can take care of their line movements by setting up the desired station and unit pumping combination that will attain the best line efficiency.

The maintenance, repair, inspection, experimental, and all policies pertaining to this program are under the direct supervision of the mechanical department at Dallas and are put in effect through the district machinist and district superintendent of the line.

Maintenance policy. All stations are equipped with the best possible selection of tools, special apparatus for routine maintenance, and all essential material so that all classes of work can be readily performed at each station. However, since we do not have a spare unit in our stations, and as the line is operated near its maximum capacity, we keep a very adequate supply of repaired parts and spare parts on hand to meet any emergency that may present itself. We prefer to change parts or make repairs when they first show signs of giving trouble and parts are replaced at once instead of using the policy of getting more out of a part.

Maintenance program: Exhaust, inlet, and spray valves. We have three extra heads at each station for one make of engine and we grind valves on these engines every six weeks. We grind the valves on one engine on Tuesday and on the other engine the following Thursday. On the other make of engine, we carry six extra valve cages and valves and grind valves on these engines every eight weeks. We grind valves on one engine Tuesday; on the other Thursday.

It requires about six to eight hours of shut down time to grind valves on one make of engine and about four hours of time on the other make of engine.

All spray valves and fuel delivering valves are checked, cleaned, tested, or adjusted during the exhaust and inlet valve grinding period. The cylinder liners are inspected and records are made each time the valves are ground.

Crankshaft and main bearing inspection. From past experience and inspection data on record our plan is to make our crankshaft and main bearing inspections every two years. In nearly five years of operation we have never had a bearing failure on any of our engines. We have had bearings which have been flaked, but these were repaired.

Piston, ring, and liner inspection and maintenance. Close daily and monthly checks are kept of our lubricating oil consumption and blowby indications, and the pistons are pulled when our lubricating oil consumption falls below 1000 hp.-hr. per gal. We do pull pistons for inspection when excessive blowby or some particular reason exists that necessitates this work, and we do not hesitate to do this after consultations between the chief engineer of the station and the machinist.

All engines on this system have been in service long enough so that we now have definite plans as to ring procedure and maintenance. We have kept accurate reports on all pistons, rings, and liners on every engine and we know the best combinations to use to suit the engine requirements.

Two-piece rings are used on tapered and out of round liners. Chromium plated rings are used for special conditions. We also use various combinations of oil cutter, scraper drain, and beveled and grooved oil rings to suit the cylinder wear conditions.

Indicator program. After every valve grinding, each engine is indicated (by pull card method) and the compression and firing pressures recorded before and after adjustments and records are made of these readings. The machinist does all engine indication and makes out the necessary reports. The chief engineer also records these pressures in the station daily log. Whenever an engine has a cylinder or spray valve that is not consistent in its operation, we immediately indicate the cylinder in question to find the trouble.

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We find from experience that firing pressures equal or higher than those recommended by the manufacturer have to be maintained for our load conditions. The machinist makes all the necessary injection point adjustments. They are subject to call at all hours in case a chief engineer requires engine indication or other assistance.

Fuel system and spray valves. I will state that all the engines are equipped with the Bosch fuel injection system and with crude oil used for fuel, it is absolutely necessary that the fuel be clean for good operation.

Line crude is warmed in the cold periods, and after being centrifuged, it is pumped to an outside, overhead, 250-bbl. capacity, conical type bottom fuel tank. The fuel is drawn from this tank from a point above the conical bottom to two elevated 100-gal. day tanks in the station. The fuel from these day tanks is pumped by a small rotary pump through duplex filters to the engine manifold and the fuel not consumed by the engine returns to the elevated day tanks. We have found that a small pressure must be maintained on the engine fuel manifold and that with the constant circulation of the fuel back to the day tanks we eliminate gas pocket formations. By this method the fuel is continuously filtered. In order to check the condition and operation of our crude oil centrifuge, we hand-centrifuge a sample of the inlet and outlet crude each day and in this way eliminate the possibility of dirty fuel. We steam out our fuel lines and fuel tanks every two years.

Pyrometer hourly readings are recorded in the station log. Whenever any particular cylinder will not remain consistent with the others or whenever the exhaust shows hazy conditions, even for a 15-minute period, the engineer must locate this trouble and make the necessary spray valve or fuel pump inspection or corrections.

Our engineers realize the importance of this procedure and carry out in every way the instructions issued.

All "lapping in" work on spray valves and fuel injection pumps is done by the machinists. Sufficient spare spray valves and injection pumps are carried at each station to meet our operating maintenance requirements.

Lubrication. Centrifuges and Fuller's earth type filters are used to clean the lubricating oil. Each engine is equipped with a large size filter with attached heater. A "refill" is used for an average of 27 days before it must be renewed, this being governed by the condition of the engine. The centrifuge operates alternately every four hours on the engines and we use the separator principle of operation in order to check for possible water leaks to the engine crankcase. Naturally, the filters do most of the cleaning, but using the centrifuge in conjunction with the filters gives added protection to the unit.

The cost of cleaning our lubricating oil is approximately 50 cents per day per engine. The filters and centrifuge take out about 7½ lb. of carbon, etc., each day per engine. The use of the filters definitely has helped to eliminate some of the varnish deposits on the pistons and liners, which helps to prevent scuffing and furring. We find that we get the best lubrication for the pistons, rings, and liners with a lubricating oil consumption of between 1500-3000 hp-hr. per gal. Sometimes after an overhauling our lubricating oil consumption is more than 5000 hp-hr. per gal., and when this occurs we take the necessary step by ring and pump adjustments to lower this value. Whenever we locate a cylinder that tends to allow the lubricating oil to pass by the piston rings, we pull the piston as soon as it is convenient to do so and clean the rings and make the necessary adjustments.

The temperature of the lubricating oil in the crankcase is maintained at approximately 135° F.

Cooling water system. The enclosed system is used on these engines and a suction type of heat exchanger is used for each engine. One heat exchanger is of sufficient size that it can

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cool both engines. Each unit has its own chain-driven, centrifugal circulating water pump, which is large enough to take care of both engines. The surge tanks are double connected so that the circulating system on one unit can be used in an emergency for the other unit. The speed increaser units have their source of cooling water from the engine cooling system. The circulating water, raw water, and exhaust heat boiler water at each station is checked each month for scale and corrosive properties. We have no scale in our water jackets or cylinder heads. The water outlet temperature from the engine is regulated to 120° F. and the inlet temperature to 110° F., and we find for our operating conditions that this control works out best.

Main pumps and speed increasers. All maintenance and inspection work on the pumps and speed increaser units is under the direct supervision of the machinists. All pumps are equipped with mechanical seals and have been giving excellent service.

Our main pumps have given very little trouble and the maintenance cost has been very small. We have found that after the first initial wear on the impeller wearing rings that with careful operation very little wear occurs. We attribute the small maintenance on the impeller wearing rings and mechanical seals to the fact that we have strainers in our incoming line to the heat exchangers and to our method of closing off this line while the scrapers pass the station. Small individual strainers have been installed ahead of each mechanical seal as an added protection. The engine r.p.m., together with the differential pressure that a pump is capable of putting up, definitely indicates the true condition of the pumps.

Our 17 speed increaser units from three different manufacturers have given excellent service and are quiet in operation. Oil pressure relief valves were installed in the lubrication system of these increasers as an added feature of safety. We change oil in the increasers every six months.

Observations. The operating personnel of this was carefully selected for its various duties at the time the line was put into operation for the reason that this line operates under the supervision of the Dallas office through the district superintendent and the district machinist. The line's successful operation has proved that the effort in making our selections has been well worth the effort involved.

We definitely have kept the supervision of this line under as few supervisors as is possible to eliminate confusion of orders or instructions. We also found that this line, because of its distance and available communication service, requires explicit and intelligent orders and instructions that can be carried out and at the same time protect all of the operating personnel.

Due to the fact that the units in each station generally operate in series and that all stations are in series with each other, it places each station in the position as part of a "chain" or in the category of a "link." This point, therefore, brings out the fact that the station personnel can give their whole, undivided attention to their own station. This is not generally true with stations that operate with floating tanks or by the "in and out" method of operation.

We have made accurate reports and records of all necessary and important parts of our operation and maintenance.

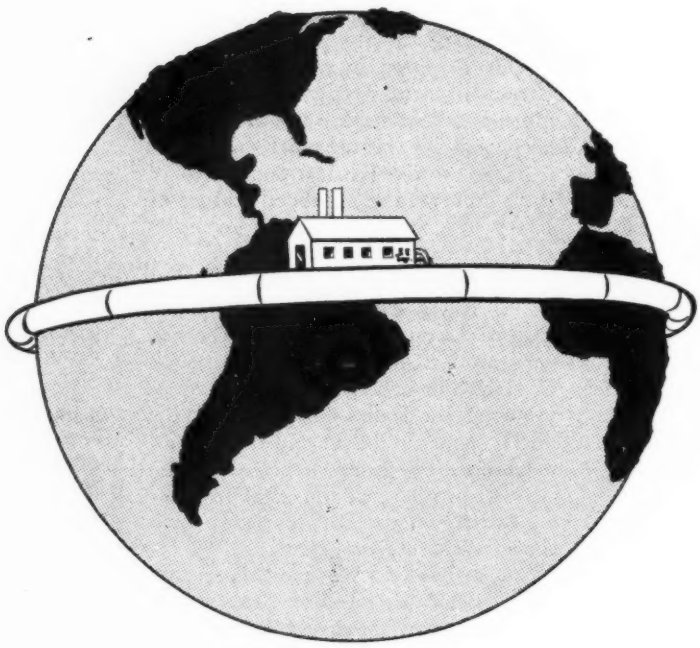
Conclusions. The writer has tried to cover only the most important points in a general way in our maintenance and operating program and I hope that I have brought out the point that we do try to operate this line in an efficient and thorough manner. The cooperative spirit of all the operating personnel has proved that this line can be maintained with a minimum of shut downs or lost operating time.

The operating record of this line without spare units tends to bring out the point that, perhaps, we obtain better results from our personnel by not having spare units because every piece of equipment is maintained at the proper time.

It may be suggested that a portion of this line's splendid showing is a direct reflection that each and every man is doing his part for the war effort in the transportation of crude oil.

☆ ☆ ☆

Enough Pipe Line to...



Circle Globe at the Equator, and Cross America Twice.

In 1915 Williams Brothers laid their first pipe line—18 miles of 8″ natural gas line in Arkansas. Since that time they have built 30,000 miles of pipe lines—enough to circle the globe at the Equator, plus enough to cross America from Jacksonville, Florida, to Los Angeles, California, and back again.

And during two world wars, Williams Brothers have been privileged through their modern equipment, broad experience and army of trained workmen, to contribute substantially to the construction of important pipe lines which history might well record as "Lifelines of Liberty."

The confidence of private industry, governments and military authorities at home and abroad has always inspired our best effort.

WILLIAMS BROTHERS CORP.

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Transportation Problems of the Oil Industry*

By SIDNEY A. SWENSRUD, Vice President
Standard Oil Company (Ohio)

THE tremendous importance of petroleum transportation, not only within the oil industry, but to the entire activities of the nation in peace and in war, probably has not heretofore been fully understood or appreciated. This was particularly true, we believe, because in the working out of its highly developed integrated structure the oil industry had created a specialized transportation system all its own, having relatively little relation to ordinary transportation media. Few people realized that our country was underlaid with several hundred thousand miles of pipe lines. Few knew that the largest merchant fleet in the world consisted of the tankers of a United States oil company, or that in the field of trucking a majority of the largest fleets in the United States were those of oil companies, or that the oil industry was one of the largest users not only of our inland river system but of the Great Lakes as well.

These comparisons serve to explain why when something suddenly interferes with the operation of this ordinarily smooth running, inconspicuous transportation system, the repercussions produce a host of extremely complicated problems, and it brings home to a large proportion of the population the importance petroleum products have attained in our everyday lives.

The *wartime* importance of petroleum transportation is too well known to need elaboration here. Such importance has been rather dramatically summed up in a statement that petroleum products, including bunkering oil, constituted more than two thirds of the total cargo that accompanied the recent expeditionary force to Africa. When we consider that virtually every moving piece of military equipment is propelled and lubricated by petroleum products and that the chief ingredient of high-powered explosives—toluene—also comes largely from the oil industry, and when we consider the far-flung, world-wide nature of the present conflict and the limited areas of supply, we can realize how stupendous is the task of transporting these requirements to the various theaters of war.

As for its importance within the industry, transportation of crude oil and of products appears to account for 20 to 25 per cent of the total revenue that the industry, including marketing, finally receives from the public for its products. Thus transportation, which is one of the four great divisions of the industry—that is, production, refining, transportation, and marketing—is about equal, as measured by the share of revenue it receives, to the average importance of the other three branches.

Historic review. Before we come to a discussion of present day problems, it will be well to review briefly the development of transportation in the oil industry, and the way in which this development has influenced or been influenced by other factors.

At a very early date in the industry's history, pipe lines came to be used for transporting crude oil, and until crude-oil production moved down toward the Gulf Coast, pipe lines were the only important form of transportation of crude. Tank-car movement of crude, from very early in the development of the industry, ceased except as a temporary method of transportation, as in the early stages of new fields or for movement of small quantities of crudes of special quality.

Pipe lines versus tankers. When crude production reached the Gulf Coast area, tanker transportation became the predominant method of moving crude oil or its products from that area to the Atlantic seaboard, and now that the new "Big Inch" pipe line appears to challenge even the peacetime economics of the tanker movement, it is interesting to consider why the tanker originally displaced the pipe line. We may say that a crude oil line of such large diameter is a new development, but for years we have had large-diameter gas lines, largely built by oil company subsidiaries, and probably there is no particular physical reason why large-diameter lines for crude could not have been built many years ago.

Undoubtedly the answer lies largely in the fact that no one company on the Atlantic seaboard has ever run enough domestic crude to enable it by itself to make efficient use of a crude line of large enough diameter to compete with tankers. For tankers, however, except for the advantages of organization and the spreading of overhead over a larger volume, the maximum economy can be achieved by anyone who has enough volume to keep one large tanker busy, and that requires only around 10,000 bbl. a day from the Gulf to the Atlantic seaboard, whereas to make the most efficient use of even a moderately large pipe line, say of 16-in. diam., would necessitate a use for 100,000 to 150,000 bbl. daily.

Probably another factor was that the pipe line rate structure grew up on the basis of lines of relatively small diameter and the thinking, therefore, as to pipe line rates and costs has been influenced by the habit of considering pipe line rates in terms of these historic relationships, whereas for tankers tariffs have not been required and there was no impediment to thinking entirely in terms of costs rather than of tariff rates.

Another factor, however, was that through the use of tankers the crude could be separated into its component products at the Gulf Coast. This had several advantages. Refining costs tend to be a little lower on the Gulf Coast than on the Atlantic seaboard (primarily because of lower fuel cost). In addition, when refining is done at the source, the refining loss need not be shipped at all. These advantages depend in part upon having outbound tanker transportation available, for it is not possible to move all of the products by pipe line. Heavy fuel oil, for example, cannot be shipped through a pipe line but can be transported in a tanker. These factors doubtless will continue to favor the combination of refining on the Gulf Coast, plus tanker transportation of at least a part of the products to the East Coast or elsewhere, but there is nothing in this to prevent the movement of the lighter products by pipe line.

Displacement of rail transportation. The reason why pipe lines and tankers displaced rail transportation will be discussed later on, but we may say here that we believe it was not entirely because of fundamentally higher costs of rail transportation; probably the rigidity of rate and cost-accounting concepts in railroading were equally responsible. In deciding between rail, tanker and pipe line transportation an oil company, as far as rail transportation is concerned, can consider only the tariff rates available—not the basic costs.

In the field of *product transportation* the railroads had almost a complete monopoly until about 15 years ago, except for the final local delivery made by tank wagon or tank truck, and except for the tanker deliveries from the Gulf Coast to the East Coast. After that, transport trucks, and later product pipe lines began to displace the rail movements.

Here again it is the writer's opinion that the railroads lost most of this business because of a failure to conceive the true nature of the problem and the reality of the competition, and to consider the costs of *losing* the business as well as figuring the costs of handling

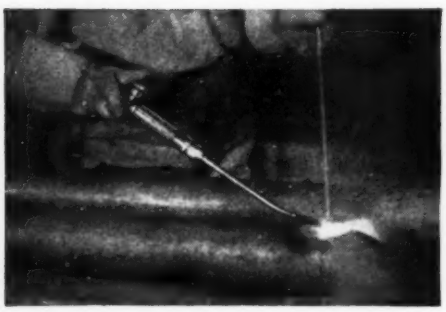
(Continued on Page 174)

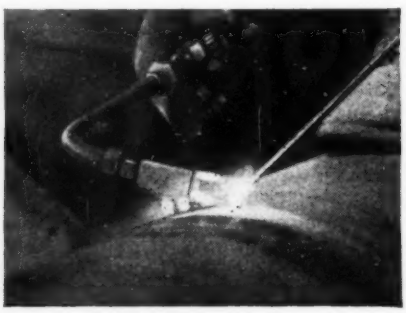
*Presented before American Institute of Mining and Metallurgical Engineers, New York City, February, 1943.

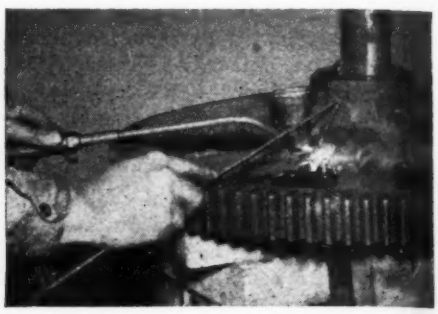
LINDE METHODS AND EQUIPMENT

Help to Maintain Production and to Lower Operating Costs

Oxy-acetylene processes are used throughout industry to speed up production and construction programs, to conserve materials, to lower operating costs, and to simplify maintenance and repair. Some of the many oxy-acetylene applications are outlined here.

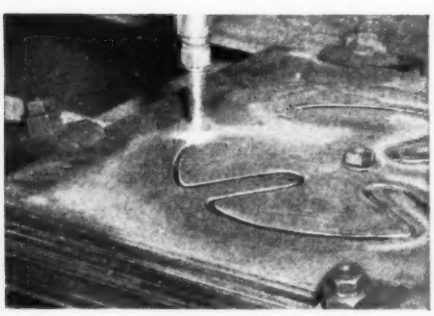






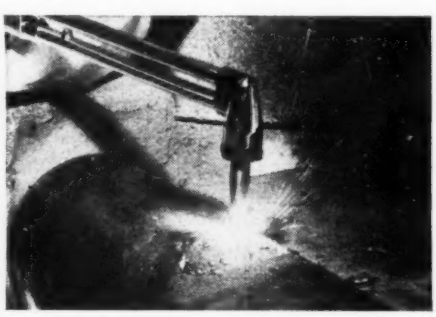
OXY-ACETYLENE WELDING

The oxy-acetylene flame makes possible the joining of practically any metals—like or unlike—so that the weld is as strong as the base metals themselves. *Welded piping systems* in plants and refineries use less fittings, occupy less space, and remain leakproof indefinitely. Overland *pipe line welding* by Linde's steel-welding process produces strong, ductile welds in pipe of any size. *Bronze-welding* and resurfacing speed the repair of worn or broken parts and hard-facing with HAYNES STELLITE alloys makes parts subjected to abrasion, heat, or corrosion last from two to twenty-five times longer.



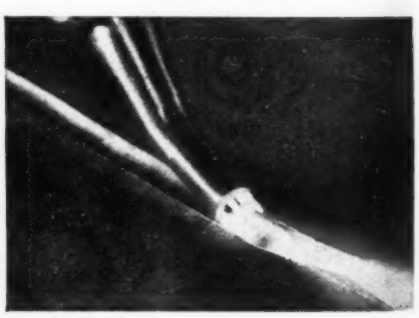
MACHINE FLAME-CUTTING

Shape-cutting with OXWELD machines quickly produces simple or intricate steel shapes with clean-cut edges that usually require no machining. Identical parts can be cut rapidly, from tightly clamped piles of plate by this method.



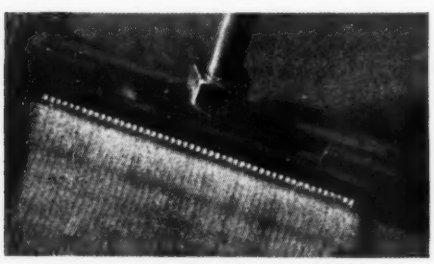
HAND-CUTTING

Flame-cutting with manually operated blowpipes is useful for cutting pipe in the fabrication of piping systems. Hand-cutting also is used to cut structural steel in construction or alteration work—to reclaim old pipe—and to cut scrap to length.



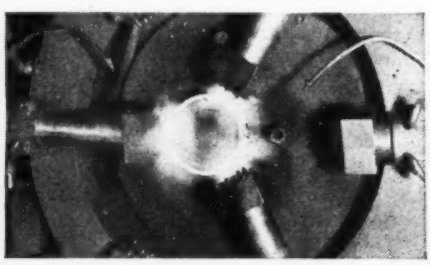
GOUGING

With OXWELD hand-cutting blowpipes equipped with gouging nozzles, a groove of surface metal—such as faulty or temporary welds—can be removed quickly, without need of grinding or chipping, and without harm to the adjacent areas.



FLAME-PRIMING

This relatively new process removes loose scale, rust, and surface moisture from steel prior to painting—making paint go on faster, bond tighter, and last longer.

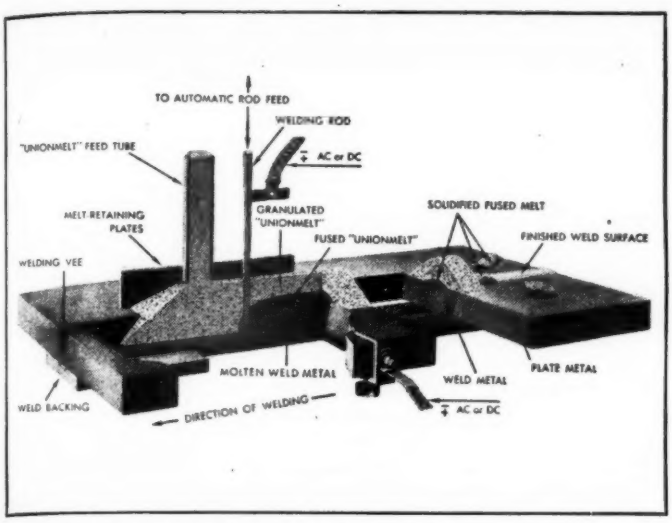


FLAME-HARDENING

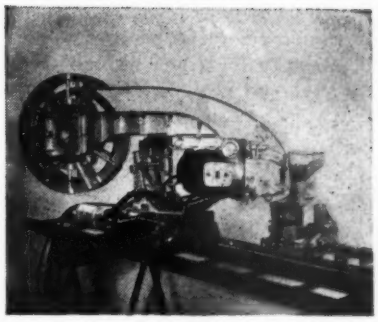
This oxy-acetylene process is used to impart a hard, wear-resistant case to steel and iron parts without affecting the toughness of the core.

WRINKLE-BENDING

The intensely hot, easily controlled oxy-acetylene flame facilitates wrinkle-bending of pipe and provides a smooth, long-sweep bend, without thinning the pipe walls.

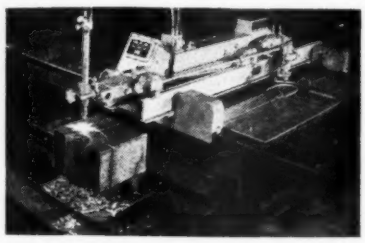


This sketch shows how a UNIONMELT butt weld is made.



UNIONMELT WELDING

UNIONMELT electric welding is a unique automatic process that makes welds of unusually high quality in any thickness of metal at high speeds. Once the speed and current values are established by the operator, the "human element" is eliminated as a factor in producing good welds. UNIONMELT welding is done under a protective blanket of a special granulated material—without flash, glare, or sparks. The rod is fed automatically as work progresses and is thoroughly mixed with the molten base metal. For these reasons, UNIONMELT welding is widely used in the fabrication of pressure vessels, pipe, railroad equipment, tankers, and ships.

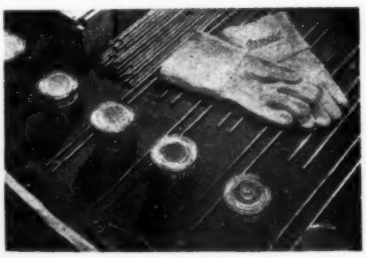


MACHINE APPARATUS

Included in the OXWELD line of apparatus are portable and stationary oxy-acetylene machines for cutting shapes or straight lines; flame-hardening apparatus; bar and billet cut-off machines; automatic welding equipment; and tractor units for plate-edge preparation.

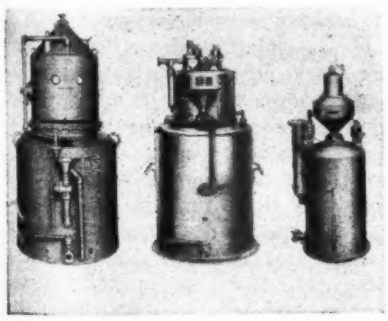
HAND APPARATUS

Oxy-acetylene apparatus which may be ordered from Linde includes oxy-acetylene blowpipes for all welding and heating work; oxy-acetylene cutting blowpipes, cutting attachments, and nozzles; and oxy-acetylene descaling and flame-priming equipment. OXWELD apparatus is supplied from Linde offices and warehouses. The PUROX and PREST-O-WELD line, and PREST-O-LITE air-acetylene appliances for soldering and brazing, are distributed by industrial and automotive jobbers.



WELDING RODS AND SUPPLIES

The many kinds and sizes of OXWELD high quality welding rods make it possible to select the one that will give best results on each job. The OXWELD line also includes fluxes, gloves, goggles, lighters, hose, and asbestos paper. Rods and supplies may be ordered from Linde or from automotive and industrial jobbers.



GENERATORS AND MANIFOLDS

OXWELD acetylene generators are made for both portable and stationary use — with maximum generating capacities of from 30 to 9,000 cu. ft. per hour. OXWELD manifolds centralize the oxygen and acetylene supply from cylinders.

OXYGEN, ACETYLENE, CARBIDE

A booklet describing use of LINDE oxygen, PREST-O-LITE acetylene, UNION carbide, and OXWELD apparatus in these and other processes will be sent without charge on request. Ask for Form 5268A.

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The words "Linde," "Prest-O-Lite," "Union," "Oxweld," "Purox," "Prest-O-Weld," "Haynes Stellite," and "Unionmelt" are trade-marks of Union Carbide and Carbon Corporation or its Units.

(Continued from Page 171)
it in accordance with typical cost-accounting calculations, which are heavily burdened with fixed charges.

Along with this was the failure, or perhaps we should say the impracticability, of the parties involved—that is, the railroads, the tank-car owners and the shippers—to give to the question of how the traffic in a particular case could be handled most efficiently the same consideration a single oil company would give to the handling of one of its own transportation problems through its own facilities; and even if this could be done, there would still be the problem of setting up a rail rate in the particular case that would give recognition to the working out of such efficiencies.

Trucks and pipe lines versus tank cars. To digress a moment on this point—it can well be imagined what pipe line or truck costs would be if movements through these facilities were handled in the same fashion as are movements in ordinary times by tank car; that is, no effort made to speed up the turn-around time by attention and time study of every aspect of loading, moving and unloading, and no effort made to increase the size of the container as a means of lowering costs.

In our own company's operation of transport trucks, we aim to keep them in active operating service about 20 out of 24 hr. In connection with trucks, much study is given to speeding up loading and unloading operations through more rapid pumping, larger delivery pipes and better scheduling, and so forth, but in prewar days very little consideration was ever given such details in connection with the movements by tank car. The point is that for trucks or pipe lines we could deal with these problems because they were within our single control, whereas with railroad transportation this was not possible, because, in addition to the railroad, the tank-car owner and the shipper there was the Interstate Commerce Commission. These, in the writer's opinion, have been the factors that have caused the substitution of other methods of transportation for rail movements rather than, or certainly as well as, any marked advantage of the other methods over rail, so far as the fundamental costs of material, man-hours, and horsepower are concerned.

Influence of transportation developments on other ends of the business. It is interesting to note how the shifts from rail to pipe line, transport truck and barge transportation have affected the development of the refining and marketing ends of the industry. When product shipments were primarily by rail, a predominate feature thereof was that large freight zones were created—referred to, for example, as Group 2 or Group 3—in which the rail rate for a shipment to a point outside the zone was the same from every point of origin within the zone—this regardless of the relative costs or distances that might be involved. Under these conditions there was no outbound rail transportation advantage in locating a refinery at one point as against another within the same zone, and the result, of course, was that small refineries tended to spring up wherever a crude field developed; since the nearer the field, the less the inbound transportation cost of the crude. When, however, rail transportation began to be displaced by truck or pipe-line transportation, and when, in consequence, delivered prices in the Middle West markets ceased to reflect fully the old "Group 3 price-plus-rail freight" basis, many of these isolated refineries became uneconomic.

Of course the larger refining companies had tended to give greater consideration to the fundamental aspects of transportation and to locate their refineries in the vicinity of the larger markets, for where there was a large enough volume involved it was generally cheaper to transport the crude oil a long distance by pipe line and the products a short distance by rail rather than vice versa.

Product pipe lines. The development of the product pipe lines and the large consumption of heavy fuel oil by the western railroads has contributed to making the location of field refineries somewhat sounder, because now the light products can be shipped by pipe line, the heavy fuel oil can be sold to the local railroad and the refinery loss need not be shipped at all.

Just why the development of pipe lines for shipping products as well as crude was so long delayed is an interesting question. Of course there never was as large a volume of any one refined product to be shipped by pipe line as there was of crude. However, in many cases there was a large enough steady movement, at least of gasoline, to warrant its delivery by pipe line long before product lines developed. There does not appear, either, to have been any sound engineering reason for the deferment, since eventually some of the oldest crude-oil lines in the country were turned into gasoline lines.

I think we must put the deferment down primarily to the fact that the larger units in the industry, which had a volume sufficient for efficient pipelining, had achieved their major saving by piping the crude oil to refineries in the large marketing centers and therefore had achieved a sufficient advantage over the marginal competition to make it possible to ship the products out by rail and still have a comfortable margin. Also, on the Great Lakes, some deliveries from refineries to other large centers were made by tanker, and on some of the rivers by barge, and this solved a further part of the problem—possibly not as economically as a sound products pipe line system would have solved it, especially as compared with tankers on the Great Lakes, which are frozen up almost half the year, necessitating large terminals and extra inventories. It may be, too that the fact that product price structures historically were based largely on rail rates was a factor in postponing the development of product pipe lines.

Whatever the reason for the delay, the progress of product pipe lines was very rapid once the ice was broken a dozen or so years ago, and the industry has now made great progress toward what we might call its "product plumbing system."

Effect of transportation changes on marketing. Nothing could have been better calculated to change the development of marketing than these various shifts in the nature of product transportation. During the rail era there were two primary facilities in petroleum marketing—the bulk plant and the service station. The bulk plant received tank-car deliveries for local distribution by tank wagon and later by tank truck. The early radius of this local delivery operation was small, and, since the material had to come in by tank car anyway, the advantage lay in a great number and scatteration of bulk plants.

Deliveries were made from these bulk plants to retail stations, and there was, therefore, a very sharp distinction between the "tank car" price to the jobber operating a bulk plant and the "tank wagon" price to the dealer operating a retail station. The distinction was real; there was no escaping the transportation realities on which it rested.

The development, however, of transport truck, pipe-line, and water deliveries has now changed this whole scene. Transport trucks can haul long distances from refineries, but, more than this, the product pipe lines and water routes have led to the creation of many pipe line and water terminals, which have the same effect as though the refinery itself had been moved out toward its markets, in somewhat the same fashion as that of the general who got on his horse and rode off in all directions.

Bulk plant becoming obsolete. It may readily be seen that under these circumstances the old-type bulk plant, which had to exist for receiving tank-car deliveries, is destined to become, and is becoming, more and more obsolete. There is no need of shipping by tank car or by transport truck from a pipe line or water terminal to a local bulk

plant if delivery can be made directly to the retail dealer or the consuming customer by a truck moving out of the terminal.

There still is a wholesaling function to be performed in the solicitation and servicing of retail dealers and consuming accounts, in the warehousing of case and barrel goods and the like, but there is an ever diminishing need of the old-fashioned bulk plant for the purpose of putting the major liquid products through it, and such business seems likely to dwindle down to that of serving the peddler type of small-size deliveries to farmers and other small consumers.

The war has greatly accelerated this development, especially in the areas where for one reason or another it had been somewhat held back by a tendency to continue uneconomic local tank-car rail deliveries. The need of using these tank cars for long-distance movements to the East has created a great pressure to eliminate them from all unnecessary local deliveries, and thus a trend, which was certain to have extended anyway, was accelerated by the war.

Effect on retail marketing. The result of these developments has been a marked change in retail marketing. The tendency of the larger, better located stations is to put in large enough tanks to receive transport deliveries in efficient quantities, and since this naturally reduces the cost of wholesaling as far as such station is concerned, the margin between the jobber price and the dealer price constantly tends to narrow. This, in turn, tends to make even more uneconomic the operation of the station whose premises or business is so small that direct deliveries in efficient volume cannot be made. As in all human institutions, customs tend to outlast the conditions that brought them about, and in the same way many of the small uneconomic retailers continued to stay on. Up to the time of this war this undoubtedly was a fortunate circumstance since it tended to mitigate the sufferings that often result from a sudden change. Here again, however, the was has tended to accelerate a development that undoubtedly was inevitable. War jobs have been more lucrative than the operation of a marginal service station, especially after its sales were further reduced by rationing.

Aspect of integration as cause and effect. We cannot pass over these reltaionships between transportation and the development of the industry without commenting upon the interrelation between the integrated form of organization, which has characterized the industry, and its specialized forms of transportation, especially pipe lines. These factors have, we believe, operated as mutual cause and effect. Had there been no tendency toward integration in the industry, and had its units never been large enough to make it possible for any one of them to consider building a fair-sized pipe line for its own exclusive use, it may be doubted whether this method of transportation, except for local gathering of crude oil, would ever have developed in any important way. But once pipe line transportation had begun to develop, the low incremental cost of pumping the extra unit through a pipe line undoubtedly had a vast influence on the development of the business. The company that was big enough to build a pipe line would start out usually with a somewhat larger capacity than it then needed, and thus in ordinary circumstances there would almost always be the possibility of putting through additional quantities merely by adding some additional pumping facilities, going to a little higher pressure, or, when these methods had been exhausted, building intermediate stations or "looping" the line.

The extra cost of handling extra oil on this basis was relatively small, and coupled with the fact that where extra refining capacity exists a similar low incremental cost factor operates, it can readily be seen that an integrated company could manufacture additional products at a cost that ordinarily would leave a sufficiently satisfactory margin to stimulate the efforts toward further expansion, even if some price concessions had to be made.

What we used to hear so much about, therefore, as crude oil pressing on the market, probably was not solely the pressure to produce the extra crude oil, but this, plus the opportunities to make additional profit from the low-incremental-cost factors involved in transportation and refining. Contrast this with the much greater incremental cost that would be applicable to an extra barrel shipped via tank car or via a pipe line owned by an outside company, when the extra barrel would carry the same cost to the shipper as the first barrel shipped.

The combination of low incremental cost and company ownership of pipe lines, therefore, probably must be concluded to have been one of the primary forces promoting the high degree of integration in the oil industry. Such integration, in turn, made it possible for the pipe lines to be built, and thus integration has, in fact, contributed very greatly to economical transportation in the industry, most of the benefits of which in the form of lower prices, have been passed on to the consumer.

Wartime problems. The displacement of rail movements of petroleum products by less expensive pipe-line and tanker movements in the years past, in addition to providing cheaper transportation, turned out to have been a national blessing for another reason as well, for it resulted in there being on hand an extra, unused, or only partly used, form of transportation that could be impressed into service as an emergency measure. It is interesting now to look back at the controversy that raged in 1941 as to whether or not there were 20,000 tank cars available in the United States which could be put into long-distance tanker-substitution service. It will be recalled that most of the authorities in the Petroleum Coordinator's office, including some of very high rank, took violent exception to the idea that there was any such number of tank cars available. That they were slightly in error is attested by the fact that at present there are somewhere between 70,000 and 80,000 tank cars in this service! Nothing could better illustrate the importance of a proper concept of a problem.

Those of us who had spent many years working on the substitution of other methods for expensive rail deliveries had little doubt that the great majority of tank cars, in fact, could be freed for such service merely by carrying the substitution of nonrail methods of local delivery a good deal farther, and, if necessary for this purpose, building some additional trucks, inasmuch as even a small truck will displace 10 to 20 tank cars. A tank car in a local short-distance movement is almost unbelievably inefficient in terms of the barrel miles of transportation accomplished per tank car per day, because of the disproportionate amount of idle time during which the tank car is being switched around or left standing in yards awaiting the arrival of trains. And, of course, the recipients of tank cars had formed the habit (entirely justified when there was a surplus of tank cars) of unloading them pretty much at their leisure, since ordinarily they were allowed 48 hr. or more of free time after the arrival of the car in which to get it unloaded.

Concept should be trains instead of cars. The difficulty of getting people to change their concepts of such matters is well illustrated by the disproportionate emphasis placed for a long time on the "time under load" factor; that is, the time elapsing between the time the loaded car was taken from the loading rack and the time it was delivered to the destination. But, of course, from a standpoint of maximum deliveries over a period, the time spent in moving the loaded car was not one iota more important than the time spent in loading and unloading and in returning the empty car.

Another concept which it has been difficult to inculcate was that since the tank cars were being substituted for

tanker hauls they could be most efficiently used if arrangements were made to load them and unload them in trainload lots, just as a tanker would receive a quantity (equivalent in fact to many trainloads) from one terminal and deliver it as promptly as possible to another terminal. Instead of this, the tendency was, and still is to some extent, to disperse the cars when they arrive near the destination and use them to make a great many small local deliveries to individual customers and bulk plants, thereby merely doing with the precious tank car what could be done several times more efficiently with a local truck. There would be some extra cost attaching to subsequent truck delivery, but from the standpoint of maximum utilization of tank cars there could be no question whatever of the efficiency of unloading the trainload as a unit and getting the empty cars started back promptly and as a unit.

On the whole, of course, the oil companies and the railroads have done a creditable job in making tank cars available from local services and getting the deliveries to the East up to the figures that have been reached. But it is believed that such deliveries could be still further increased with the same number of cars if we thought more in terms of trains rather than tank cars, and if we handled the trains as nearly as possible in the same way that tankers would be handled if they were available.

Other projects. The use of tank cars is but one (although by far the most important) of several means of increasing deliveries to the East Coast.

The most important other project is the new 24-in. pipe line from East Texas, the first part of which, ending at Norris City, Illinois, is just being completed, with an extension to the East Coast under construction.

Three gasoline lines, formerly running from the East Coast to the Ohio River Valley area, have been reversed and are now carrying crude oil or products eastward instead of westward. To facilitate these eastward movements, certain connecting links have been built and other previously existing links enlarged, so as to make it possible to bring to the head of the reversed pipe lines enough volume to keep them operating at full capacity.

Pipe lines of used pipe. Several other pipe line projects have been built out of used pipe. including a line from Beaumont, Texas, to Baton Rouge, Louisiana, to supplement or take the place of barge deliveries via the Intercoastal Canal, in order to make available additional quantities at Baton Rouge to feed the eastbound Plantation products line, running eastward through the southern tier of states. The Plantation line, which was built in 1941 as far as Greensboro, North Carolina, was recently extended to Richmond, Virginia, and its capacity increased to handle the extra movements.

Another line was built out of used pipe from El Dorado, Arkansas, to Helena, Arkansas, on the Mississippi River, and certain crude oil lines formerly running south from El Dorado to or toward Texas were reversed and converted to product deliveries in such a way as to make it possible to get enough refined products to the head of the El Dorado-Helena line to keep it operating at capacity.

Still another used pipe project is a line across the northern part of Florida, which makes it possible to take gasoline delivered to the west coast of Florida by barge or tanker and deliver it to the east coast without having to circumnavigate the whole peninsula.

Great Lakes tankers. Successful programs also were developed to increase the usefulness of Great Lakes tanker facilities by rearranging deliveries, through exchanges, improvement of loading and unloading facilities and other measures, so as to eliminate cross hauls and maximize eastbound deliveries. Some new barging and towing equipment has been built, and a substantial number of dry-cargo barges have been converted to oil carriers.

New pipe lines proposed. Now being proposed is another large-diameter (20-in.) new pipe line to run either (*a*) from the Beaumont, Texas, refining area up to a point in Indiana, or (*b*) from a Middle West point on to the East, and in either event the other leg might later be built so as to make another large-diameter through line from Texas to the East. Some controversy has developed as to which leg of this line should be built first, and the matter has attracted the attention of one of the committees of the United States Senate.*

One of the problems that frequently arises in consideration of transportation problems is the fact that crude oil production in the Middle West and Mid-Continent areas, especially in Illinos and Oklahoma, is tending to decline and this means that on the average crude oil will have to be brought from more distant sources for use in the interior refineries, generally referred to in the War Administration as District No. 2. At some point, therefore, it seems probable that additional pipe line capacity for crude from Texas into Oklahoma will be found essential. There are great reserves of crude oil in West Texas, and additional pipe line capacity for moving oil from that area into Oklahoma probably would be found to be a desirable means of increasing crude oil availability in District No. 2 in such a way as to ensure the continued full use of pipe line transportation capacity from Oklahoma northeast, and to assure the necessary quantity of crude oil required by the refineries in the interior area. The preoccupation of most of the government authorities with the solution of the East Coast shortage problem, and the fact that thus far it has been possible to draw on previously accumulated stocks of crude oil in District No. 2 sufficiently to offset production declines, has postponed attention to this problem, but such stock reductions obviously are a negative type of solution, and it would seem that in the near future the problem will have to be dealt with in an affirmative manner by providing pipe lines for bringing additional crude oil into District No. 2 for use therein.

Wartime operating problems. Operating problems under today's conditions can be epitomized by saying that operations are being conducted at as nearly 100 per cent capacity as possible (in many instances at reduced safety factors) while being limited and hindered by lack of materials, inferior substitute materials, reduced manpower, and increased inefficiencies of labor.

Considering these factors in their order: It is impossible often to obtain first-class material, and even substitute or used material involves delays and obstructs repair or construction schedules. In one pipe line project recently completed, it is safe to say that a month's time and several million ton-miles of transportation were lost because of inability to obtain on schedule the used materials designated for the job.

Up to the present the shortage in manpower has been felt mostly in engineering and supervisory work, with the result that many men occupying these jobs are reaching the limit of time that they can apply to their work. Government regulations and reports contribute not a little to this problem. Within the past six months there has been a noticeable decline in the efficiency of labor, evidenced by careless work and by the tendency of men to leave for no particular reason except perhaps a feeling of independence. It is not unreasonable to look forward to the time when existing transportation facilities will deliver fewer ton-miles as a result of these factors.

Exchanges and joint use of facilities to save transportation. We hear a good deal about exchanges and joint use of facilities. In the prewar days, the industry was greatly criticized for making gasoline exchanges, as though there were something reprehensible about one company getting gasoline from another company's refinery or terminal. The

*United States Senate Special Committee to Investigate the National Defense Program.

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true importance of those exchanges is now being recognized and, instead of the government objecting, it is now urging or ordering the making of such exchanges wherever possible. The fact is, of course, that the exchanges were always a method of minimizing transportation, and in past times the public benefited through the lower prices resulting from decreased costs, just as today the country is benefited by the greater utilization of transportation facilities that is possible through exchanges.

The joint use of facilities which is being discussed at length is simply a further application of the exchange idea, for exchanges themselves are in effect joint use of facilities. There is, of course, a considerable difference between arrangements voluntarily worked out, where the pressure is lowering of costs, as contrasted with arrangements made pursuant to an arbitrary plan, which theoretically might appear to be well-nigh perfect, but which might go so far as to qualify substantially the fundamental competitive nature of the business. The standard, of course, must be wartime efficiency. But probably a general observation may be made that the theoretical efficiency of any plan that deviates widely from current practice and requires a good deal of administrative procedure to carry it out must be subject to a substantial discount factor, and this is especially true if, in addition to burdensome administrative problems and costs, the changes involved appear to be in the direction of permanent socialization. Probably it is actually more efficient to get 70 or 80 per cent of the theoretically possible accomplishment, by some plan that leaves as much of its application as possible to individual operators to work out, with ample following up, analysis and reporting of progress by the industry committee or government agency concerned.

Postwar problems. We are beginning to hear more and more about dealing with the postwar problems, which will have arisen out of the war. A great many such problems can be posed in regard to petroleum transportation, for in that, as in refining, large new facilities will have been created as a result of the war, and the use of these after the war undoubtedly will have a very great influence upon the course of the industry's development.

Can or will the "Big Inch" pipe line (or lines), for example, continue to haul crude oil or products all the way to the East Coast after the war in competition with tankers? Will these lines continue to be owned by the government or will they be sold to oil companies? In either case, would it not be necessary, in order for them to compete with tankers, for their *tariff rates* as well as their *costs* to be in line with tanker costs? If, however, the rates were reduced to such a level, would deliveries be made to intermediate points at proportionate rates, and if so what would be the effect upon existing pipe lines and refineries?

What will be done with all the barging equipment that is constructed or reconstructed during the war? Will there be enough of the kind of traffic that barges, as contrasted with other methods of transportation, can handle efficiently to keep this long-lived equipment in service? Or will many of the oil barges be converted after the war to the handling of other commodities for which pipe-line transportation is not available and for which the principal competition is from the rails?

What will be the rail picture after the war? Will the railroads, having discovered, if they have discovered, that they might be able to handle well-organized large-volume petroleum movements at low cost, make a bid for holding this business after the war and get their rates down to a point where they could compete with pipe lines or water movements? (If we were to make one prediction, it would be that this will not occur, since it would involve a greater change in the ratemaking concepts of the railroads and the Interstate Commerce Commission than seems likely to occur.)

What will be the fate of the tank-car companies after the war? Will they regain enough of the local business to provide fair use for the good cars left after the war, or will there be enough increase in tank-car movements of other liquids to fill the gap?

What will be the influence of all the new transportation facilities upon refinery operations and locations, and upon marketing developments? What, indeed, will be the industry's total volume of petroleum and its products to be moved after the war? How rapidly will the automotive "population" be rebuilt? Will prices of crude oil remain low enough to keep petroleum fuel oils competitive with coal and other fuels? What will be the export requirements in the reconstruction period?

These are some of the questions and problems that the industry will be facing after the war. It would be futile in such a paper as this to do more than merely mention them, but it is apparent that they will require the best efforts of the industry for their solution—we may venture to suggest that the difficulty involved in dealing with them will probably be in about inverse proportion to the growth factor of the industry in the postwar period, as influenced by the general economic and industrial situation. —— ☆☆☆

Symposium on Combating Internal Corrosion of Products Pipe Lines*

By JOHN M. PEARSON, Sun-Susquehanna Pipe Line System

A. Description of system and its capacity. The Sun-Susquehanna Pipe Line System is a system composed of four operating companies. The Pennsylvania company is the Susquehanna Pipe Line Company, with lines extending between Twin Oaks, Pennsylvania, and the state borders near Youngstown, Ohio, Binghamton, New York, and Washington's Crossing, New Jersey. The first 2 lines are 6 in. and the last is 8 in.

In Ohio the operating company is the Sun Oil Line Company, with a 6-in. line from the Susquehanna Pipe Line terminal to Cleveland, Ohio. For the duration, this line is pumping east into District 1, via the west line of Susquehanna. Tenders are delivered into the system by the pipe line of The Standard Oil Company (Ohio), at Randolph Station near Akron, Ohio.

In New York the Sun Pipe Line, Inc., 6-in. main line crosses the state from the Susquehanna terminal to the city of Syracuse, New York.

In New Jersey the 8-in. line of the Middlesex Pipe Line Company crosses New Jersey to a terminal in Newark.

Inasmuch as the system was designed to deliver products to market, there are 20-odd delivery terminals and spurs connecting with facilities owned by shippers.

The 6-in. west line and stations have a capacity of 15,000 bbl. per day of gasoline, the 6-in. north line a capacity of 8,000 bbl. per day, and the 8-in. east line a capacity of 36,000 bbl. per day. When products heavier than gasoline are pumped, the capacity is somewhat reduced, both on account of the maximum permissible line pressure and on account of the overloading of pump motors. Maximum working pressures at present are 1000 lb. per sq. in. in the 6-in. and 8-in. systems.

The majority of pump stations are fully automatic, and use electric power. Byron-Jackson and Gould pipe-line pumps are used, driven by base-ventilated squirrel-cage motors built by Elliott, Allis-Chalmers, and General Electric to our specifications. The automatic control methods are a development of our engineers, and have been described in previous publications, [1a, 2, 3, 4]

The distance between pump stations is determined largely by the profile of the line, so that the station spacing is less on the approach to the Alleghenys than on the downslope. The average spacing on the 6-in. west line is 34 miles. On the 8-in. line, it is 28.5 miles, and on the north line, 92 miles.

Inasmuch as the Susquehanna Pipe Line was one of the first to be designed for products distribution, there was little past experience from which to draw. Accordingly, the first 32 miles were laid to Icedale, where the east and north branches were to originate at a tank farm. During construction the tanks were filled, and the design calculations were found to check remarkably well in the new pipe. As internal corrosion was not anticipated, no provisions for line cleaning were made.

With the line in operation, friction measurements were made by taking pressure readings at numerous line vents while the pumping rate was held constant. These readings, corrected for elevations, served to check the linearity of the hydraulic gradient. Observations of this type, continued for some time, were eventually conclusive in showing that the friction was uniform within the limits of error over short line segments such as between pump stations. There were, however, considerable differences in friction in segments of line near and remote from the source of products. How much variation existed is illustrated in Fig. 1, which shows the increase of friction with time and the improvement realized by scrapping. For the purposes of this graph, friction data were reduced to the equivalent of 500 bbl. per hr. of 60-deg.-A.P.I. gasoline, using the relation:

$$P = K \frac{Q^a \sigma^{a-1}}{D^{3+a} \mu^{a-2}} L$$

Where:

P = lb. per sq. in. friction loss in L miles at . . . .
Q = bbl. per hr. pumping rate with fluid of . . . .
σ = density
μ = absolute viscosity
K = dimensionless constant

This relation represents any friction measurements we have made well within our limits of error, and the most probable value of a varies from 1.90 to 1.94. (This is slightly higher than the value of 1.85 often used in the modified Hazen-Williams formula.)

Although the corrections of the observations plotted in Fig. 1 are made using a=1.90, the C values were calculated on a slide rule based upon a=1.85 to correspond with accepted usage of the formula. Actually, inasmuch as the test rates usually were of the order of 400 to 550 bbl. per hr., the differences in corrections are within the limits of observation whether 1.90 or 1.85 is used for a.

B. Means for combating corrosion. In the case of the Susquehanna Pipe Line and connecting systems, the internal corrosion of the line has presented chiefly a problem of maintenance of capacity. No evidence has yet indicated that serious internal pitting or reduction of wall thickness has occurred. In a previous report[5] a summary of the quantitative data on internal corrosion

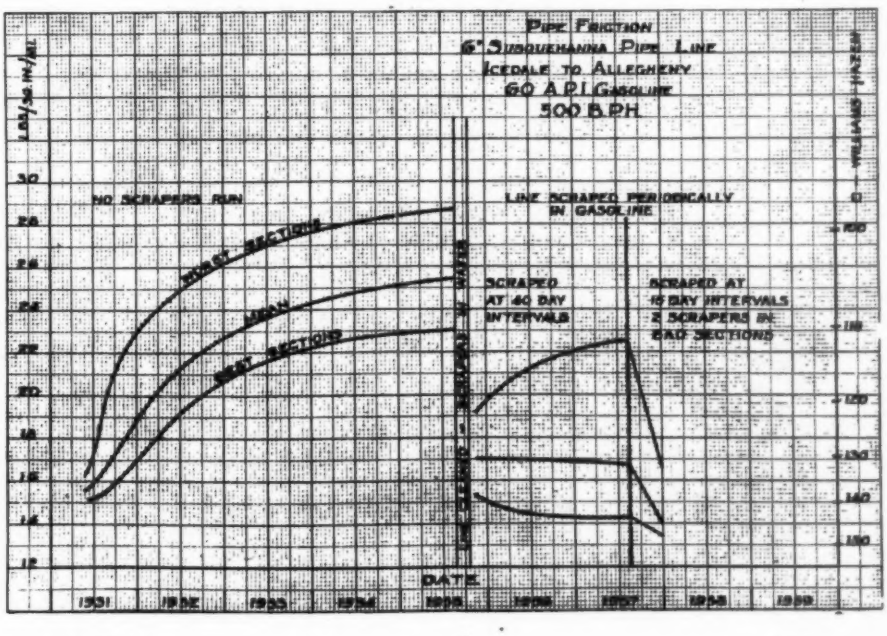

Fig. 1

*Presented before American Petroleum Institute, Chicago, Illinois, November 9, 1943.

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in several systems was given. Since that time, due to World War II, the experiments and observations on the Susquehanna System have been very little advanced. The next section of weighed pipe described in the report is due for removal in October, 1944. There is, however, still no reason to suspect that internal corrosion of the Susquehanna System averages in excess of 0.1 per cent of the pipe wall per year. Owing to the reversal of half the system, the higher rates of corrosion may now be expected in the opposite end of the reversed line. The total débris removed per month, from scraper tanks and strainer baskets, is substantially the same now as in the past.

The use of small test specimens introduced into the line has been entirely discontinued, because the data so obtained bore no useful relation to data taken from much greater areas of internal pipe wall in actual service.

The cause of interior corrosion is most apparently the water film which adheres to the inner pipe wall. In the presence of gasoline, or other products lighter than about 38 deg. A.P.I. gravity, the pipe wall is more easily wetted by water than by the products pumped. In the case of less refined heavier products, some of the waxy constituents appear more able to wet the pipe wall than water and, therefore, tend to cover and protect it. In any case, the presence of the water film provides the mechanism needed for corrosion at low temperatures, and the oxygen which can dissolve into the static water film from the stream provides ample electrochemical energy for the process.

In an untreated, unscraped line, the corrosion takes the form of small tubercles, each surrounding a small anodic area. The border of each area which is not corrosively attacked is cathodic due to the higher oxygen concentration. Because of the thinness of the water film, the resistances of the electrolytic paths to the local action currents are increased as the tubercles grow. This eventually tends to limit the amount of corrosion from each anode, and to foster the formation of new anodes at adjacent points. Such a behavior is similar to corrosion in moist air.

The rate of attack is multiplied greatly by the presence of a good electrolytic, especially one containing halide anions. Because of the greater conductivity, the pits can grow both wider and deeper.

The amount of water adhering to the pipe wall is difficult to determine. We estimate that the Susquehanna 6-in. line as presently scraped retains about 1½ to 2 bbl. of water per mile. If more were retained, it would measurably affect the line displacement.

The oxygen content of the gasoline is unknown at present, and is probably more variable now than in normal times. However, in order to oxidize the amount of iron removed as scale in one year, the average oxygen delivered to the pipe wall by the stream would amount to one part in 100,000 by weight of gasoline pumped. This is about one-tenth the amount of oxygen by weight required to saturate the gasoline stream at atmospheric pressure.

In view of the small total amount and even distribution of the interior corrosion, the chief problem presented is that of maintaining enough line capacity. At present this can be accomplished economically by systematic scraping. On the average, two scrapers once each fortnight will maintain *C* factors of from 135 to 145; two scrapers once each week tends to reduce the differences in line friction, and the values of C approach 145. More frequent scraping has not been systematically tried.

In general, the internal corrosion and the scrapers used to maintain the needed capacity have had no bad effects on the products pumped. The specifications of those products from which débris has been separated have remained satisfactory to the shippers, and no deleterious effects have been noted in our observations.

Scraping the line is done with simple rigid shaft-brush type of scrapers which depend upon the brushes and rubber driving disks to keep centered. The shafts are hollow, the ½-in. bore being restricted to a ¼-in. orifice in the rear end of the 6-in. scrapers and to a ⅜-in. orifice in the rear end of the 8-in. scrapers. The fluid passage provides a jet to assist in freeing a scraper which may become jammed on débris. If the scraper does not free itself, the noise of the jet makes it easier to find.

The orifice is at the rear of the shaft, so that particles small enough to enter will pass on freely through the bore.

Scrapers are run in pairs spaced 15 to 30 min. As they approach a pump station, the stream is turned into a settling tank which receives and settles out all débris. When scrapers are run regularly, the second scraper usually brings very little débris, and the stream behind it is clear and is turned back through the pumps.

When conditions occur which preclude regular scraping, it is usually found best to run more than two scrapers at a time or to run pairs of scrapers at more frequent intervals to restore the line to its usual condition.

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Contribution of Gulf Refining Company and Project 5 Corporation

By WALTER F. ROGERS, Gulf Refining Company

THE products pipe lines described and discussed herein consist of two separately owned systems. The first is 312 miles of 8-in. line between Port Arthur, Texas, and El Dorado, Arkansas. This line is owned by the Gulf Refining Company. This products line resulted from reversing the direction of flow of a crude oil line used in former years to transport oil from the south Arkansas fields to tidewater at Port Arthur. The second is 151.6 miles of newly laid 10-in. line from El Dorado, Arkansas, to Helena, Arkansas. This line is owned by the Project 5 Pipe Line Corporation. Other lines deliver refined products to the tank farm of the Project 5 Corporation at El Dorado and make the difference between the quantity of products furnished by the Gulf Company's 8-in. line and the capacity of the 10-in. line. The treatment of these other lines for internal corrosion, however, is not a part of these data.

Products carried. The products handled through the 463.6 miles of 8-in. and 10-in. lines are housebrand gasoline, premium-grade gasoline, and No. 2 fuel oil. The proportionate quantities of gasoline and fuel oil handled by the 8-in. are 63 per cent gasoline and 37 per cent fuel oil. The 10-in. line handles 82 per cent gasoline and 18 per cent fuel oil.

Pressure. The most commonly used operating pressure along both the 8-in. and 10-in. lines is 750 lb. per sq. in. This is increased to 900 lb. per sq. in. at two stations as the result of greater than

average spacings and topographical features. There are 11 pumping stations along the entire system, not including the terminal station. **The spacing distance** varies from 23.39 to 61.92 miles.

Capacity. The capacity of the 8-in. line varies between 20,000 bbl. and 25,000 bbl. per day, and that of the 10-in. line varies between 45,000 and 55,000 bbl. per day. The variation is related to the product handled.

Pumping equipment. The pumping equipment of these lines is that which could be obtained under wartime restrictions which prevented a selection based on peacetime available materials. As a result, a rather wide variation in equipment is found from station to station. The power end of the pumping equipment varies from steam to diesel engines to electric motors. The pumps vary through 5¼ by 16 simplex single-acting, 5¼ by 16 triplex double-acting, and 6 by 24 duplex double-acting reciprocating pumps to 5- and 6-stage centrifugal pumps. Diesel engines and reciprocating plunger pumps are in the majority, as they are used at seven stations; one station has steam-power equipment, and the remaining three use electrically-driven centrifugal pumps.

Storage tanks. Storage tankage for in-and-out movement of the products was constructed at the origin of the line at Lucas, Texas, at the delivery point of the 8-in. system and start of the Project 5 line, which is El Dorado, Arkansas, and at Helena, Arkansas, the terminal point of the system. The first six intermediate stations use reciprocating pumps, and float a tank on the line. The last three intermediate stations use centrifugal pumps, and deliver directly into the suction of the next station. At each of these stations a small tank is connected to the line through a relief valve. This tank is used only in case abnormal pressures develop and open the valve. The tank is a safety measure entirely, and is not used except as described.

Method of calculating *C* factors. In accordance with the generally accepted practice of products line operators, the development of the internal corrosion is followed through calculation of the *C* value of the line at frequent intervals. This *C* factor is obtained from the modified Hazen-Williams formula:

$$C = \frac{162.04Qg^{0.54}}{d^{2.63}p^{0.54}}$$

Where:

C = friction factor,
Q = bbl. per hr.,
g = specific gravity of liquid handled,
d = inside diameter of pipe, in., and
P = pressure drop per mile, lb. per sq. in.

Regular monthly determinations are made of the *C* factors of this line between each of the pumping stations. This procedure has been followed since shortly after the start of the operation of the line and, as a result, the condition of the line is fairly well known. All C factors reported in the data which follow were obtained through the foregoing formula.

Operation of line to prevent internal corrosion. Perhaps the simplest method of describing the steps which have been taken to reduce internal corrosion of this line is to follow the line operation from its start. In September, 1942, No. 2 fuel oil was started north from Port Arthur, and this movement was continued until about March, 1943. During this peroid *C* factors were calculated, and were found to lie in the range 150 to 155 for both the 8-in. and 10-in. portions of the system. During this time no scale was obtained from the 8-in. line, and the only scale from the 10-in. line was that due to the gradual cleaning of residual scale and dirt from the newly laid pipe. Gasoline was started through the 10-in. line in March, 1943, and since that time the relative proportion of 37 per cent fuel oil for the 8-in. line and 18 per cent fuel oil for the 10-in. line has been handled. Until June, 1943, all gasoline tankage kept a water bottom as a regular practice, and water slugs through the line from this source were fairly common. During this time there were no scale traps in the line, and a swab-scraper program was carried out only at irregular intervals. Although no change in C factor was noted, scale particles in the product were fairly numerous—resulting in the inevitable problems of cut-packing and scored plungers of the reciprocating pumps.

It was noted that quantity of scale received at each pump station followed a cycle dependent upon the product handled. As gasoline was put into the line following a block of fuel oil, a large amount of scale was obtained at the receiving station; this amount of scale then decreased to a more or less constant quantity as continued quantities of gasoline were handled. The fuel oil following the gasoline then contained little or no scale after a small initial amount. After the block of fuel oil had passed, the first gasoline carried a slug of scale, the quantity then falling to a constant amount as before. The explanation of these phenomena is that corrosion of the pipe wall occurs when gasoline is handled. This corrosion slows materially or stops when fuel oil is handled, but the fuel oil exercises a softening effect on the scale already formed. As gasoline passes this softened scale, the loosened quantities are swept into the stream and carried along in the front of the block.

After June, 1943, steps were taken to reduce the corrosion which was occurring, even though the *C* factors of the line were still in the 150 to 155 range. It is a recognized fact that the presence of free water in the fluid pumped is the prime reason for the corrosion which occurs. It was recognized also that such corrosion as develops results in scale inclusions in the fluid stream which, in turn, severely damages both reciprocating and centrifugal pumps. Thus the first logical steps were to reduce the water to a minimum and to provide means of trapping out such scale as gets into the fluid stream. In the work which followed, no claim to originality is made or implied. The remedial measures taken are largely a direct result of the experiences of others in the products pipe-line business. Some changes in design and technique may have been made, but they are of minor importance.

Beginning about June, 1943, a constant scraper program was started. This requires the running of a 2-rubber swab scraper from each station at 5-day intervals. This scraper program is followed regardless whether gasoline or fuel oil is handled. The second step was to remove all water from all tanks containing products handled by the system, and it is now regular practice to keep the tankage dry through a constant program of tank drainage. This step has greatly reduced the amount of water handled through the system. The third step was to put scale and water traps on the suction side of each station.

These traps, for 8-in. pipe, are 24 in. in diameter by 20 ft. long, and are mounted in a horizontal position. The fluid enters the top center of the drum through an 8 by 12-in. swage, and leaves each end of the drum through a 12 by 8-in. swage. These drums are fitted with several 8-in. downspouts which lead from the bottom of the 24-in. to a horizontal section of 10-in. pipe. The water and scale which enter the top drum fall through the downspouts to the lower drum, and are withdrawn each day. This settling-drum assembly is mounted in a bypass of the main line. A high-pressure small-diameter pipe leads from the pump discharge to the upstream side of the block valve in the main line. This small-diameter line is opened, and product circulation is used to flush into the settling drum any scale which may have accumulated in the dead space before the main line valve is opened to allow fluid flow to bypass the settling drum. A similar design of drum is used for the 10-in. pipe, except that the pipe sizes are correspondingly greater. In this case

the main drum is 30 in. in diameter, the downspouts are 10 in. in diameter, and the lower drum is 12 in. in diameter.

Since this threefold program was started about June, 1943, very small amounts of scale and water have been caught in the traps, and plunger and packing troubles largely have disappeared. As an example of the quantities of water and scale caught in these traps, Station 4 during 15 days of September caught 59.5 lb. of scale and 3 gal. of water. Station 5 during 30 days of September caught 61 lb. of scale and 57 gal. of water. Of this latter amount 53 gal. were caught as a single slug. The *C* factors of the line likewise are still high. Values of *C* factor since June 1 are:

Values of *C* Factor

Station	Line size, in.	Month			
		June	July	August	Sept.
1	8	146	146	148	155
2	8	155	150	151	152
3	8	155	151	154	155
4	8	159	157	161	162
5	8	156	156	160	162
6	8	152	154	153	155
7	8	156	161	151	155
8	10	155	152	152	152
9	10	155	155	155	154
10	10	155	153	154	155
11	10	152	152	153	153

In summary, this line has been in operation for 11 months to one year on fuel oil and gasoline. Due to the precautions which have been taken to keep water from the system, and due to possible corrosion reduction from the fuel oil handled, the line still has the same *C* factor as when new. The small amount of water handled and the use of scale traps are keeping the pumps from undue wear, and repair costs on this item are not excessive. Although changes in the present method of operation may be required in the future if internal corrosion becomes serious, special treatment of the liquids handled with inhibitors has not been required to date.

Laboratory tests on internal corrosion. Inasmuch as field evidence is that the handling of the No. 2 fuel oil is without corrosion attack on the steel pipe, a few laboratory tests were made to determine the magniture of this effect. In these tests 250 ml. of gasoline or fuel oil and 50 ml. of water taken from the pipe line were placed in a pint fruit jar. Clean, weighed, steel specimens 1 in. by 2⅛ in. by 20-gauge were attached in a vertical position to the rotating shaft of a 6-place stirrer, and these in turn were placed in the test liquid. The specimens were rotated at 600 r.p.m. for 6 hours each day for 4 days. At the end of this time the specimens were removed from test, cleaned, reweighed, and the weight loss determined. In these tests the percentage of water was 16.6 per cent of the total fluid. Gasoline or fuel oil pumped through the line contains far less water than this, but it was felt that a corrosion rate obtained under this set of circumstances would be in the right direction.

Several tests of this type were made using gasoline or fuel oil as the hydrocarbon liquid. The average of these tests gave the following weight losses.

Results of corrosion tests

Hydrocarbon	Weight or loss per specimen, grams
Gasoline	0.1499
No. 2 fuel oil	0.0191

From these data it was learned that the corrosion rate of steel when handling fuel oil is only 12.8 per cent as great as when handling gasoline. It is realized that the same rates of corrosion attack were not obtained in these laboratory tests as are obtained in the field, but it is believed the ratio of attack of about 1 to 8 is applicable to field conditions, especially since they substantiate field results which show a lessened corrosion rate when handling fuel oil.

Acknowledgment. The writer wishes to thank the executive department of the Gulf Refining Company for its kind permission to publish these data.

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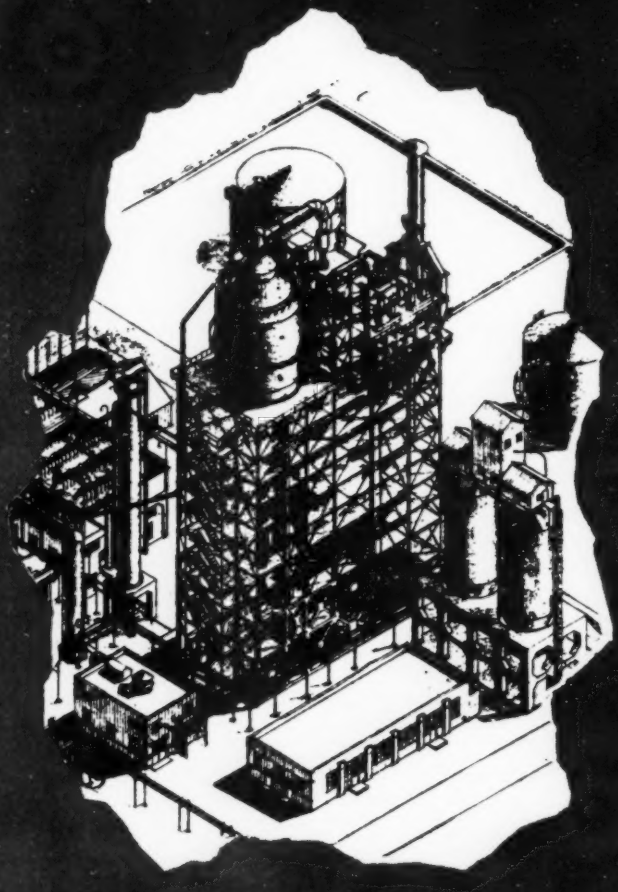

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Hydraulic Speed Control of Diesel Engines In Pipe Line Pumping Service*

By J. RAY POLSTON, Engineer
Stanolind Pipe Line Company

DIESEL engines as prime movers of pipe line pumping equipment have been in use for the last 30 years. Governors on the earlier type engines were crude and in most instances merely an adaptation of the old steam engine fly-ball type. Later designs made use of spring loaded weights, the speed variation being accomplished by varying the tension on a spring. More recent designs have made use of some of the principles of the older type governors, incorporated with a hydraulic cylinder into which an oil pressure is maintained against a piston actuating the fuel control system of the engine.

Speed regulation with the former types was not particularly accurate; however, with engine speeds of that time ranging from 150 to 200 r.p.m., accurate speed regulation of pipe line pumping engines was not an essentiality.

With the advent of higher speed engines, better governors and better control methods became imperative. These higher speed engines were found to be suitable for driving a different type of pumping equipment; namely, the centrifugal. Through a set of step up gears, speeds of 257 r.p.m. and above were readily increased to 1750 and 3600 r.p.m. These speed ranges made possible a cheaper and more flexible pipe line pumping unit than previously with the old low speed engines and reciprocating pumps. This development brought forth additional possibilities of increasing speeds of existing engine and pump installations, and supercharging of engines. With greater pump speeds and larger plunger sizes to utilize the additional horsepower developed, the need for filling the pumps under pressure became apparent.

Another problem of long standing confronting the pipe line engineer was enormous evaporation losses resulting from the old practice of floating a large tank on the suction to the pumps at each station. The oil received from the preceding station was either received directly into a tank where it was measured and later pumped out, or it was received into the suction line to the pumps, between pumps and tanks. Either method resulted in large evaporation losses. Extensive tests at one station handling more than 100,000 bbl. of crude oil daily showed an evaporation loss amounting to more than $40 per day. The need for a closed pumping system became apparent and the back-pressure control valve was designed. The installation of this device is shown in Fig. 1. This consists of a diaphragm operated, balanced-inner-valve, relief-type, spring-loaded regulator installed in the tank suction line between the tank and incoming receiving line connection. A swing check valve is installed on a bypass connection around regulator valve to permit pumps taking suction directly from the tank when pumping more oil than is received.

By carrying 10 to 15 lb. pressure on the suction of the pumps, two purposes were accomplished. First, the pumps that had been increased in speed and capacity were adequately filled, thus increasing their volumetric efficiency. Second, the oil for great distances could be kept moving through the pipe line without going in and out of tanks at each station; consequently, excessive evaporation losses are avoided.

The development of the back-pressure control valve and its use made possible a means of controlling the speed of pumping engines hydraulically for synchronizing the speed and pumping rate of one station with another. This was accomplished over a period of about one year during which several different types of devices were designed and tested.

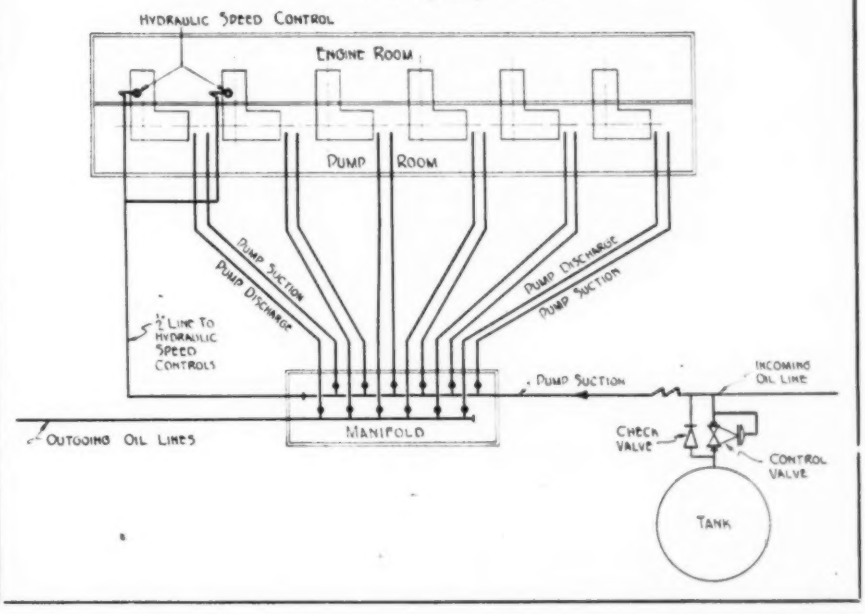
The hydraulic speed control governs the speed of the engine by positioning the governor control spring by means of pressure from the suction of the pump. Its purpose is to control automatically the pumping rate of an entire pump station or group of stations from the pressure on the incoming lines so that a minimum of liquid will pass in and out of the working tanks to reduce evaporation losses. This control is so sensitive that the pumping rate of an entire six unit pump station may be controlled by varying the speed of only one of the larger pumping units. It is advisable, however, to install hydraulic control on two engines in order to provide flexibility of operation and for shutting down to make adjustment and repairs.

Any acceptable design must permit the engine governor to operate against the speeder spring originally furnished by the manufacturer and include means for disengaging the hydraulic device for manual control. It must also provide limit stops for the traveling part of the hydraulic device to prevent the danger of excess engine speed. Excess pressures do not affect the operation. The stops are set for the minimum engine speed at zero pressure and for maximum speed at the predetermined maximum pressure. Pressure in excess of the predetermined maximum will not further increase the engine speed.

Direct piston operated control. Figs. 2 and 3 are outline and sectional elevations of a direct piston operated hydraulic control for Jahns governor on a 250-hp. engine.

The governor speeder spring is in-

Fig. 1. Diagrammatic layout showing hydraulic control on two units of a six unit pump station



*Presented before The American Society of Mechanical Engineers, Oil and Gas Power Division, Tulsa, Oklahoma, May 8-10, 1944.

stalled so it will oppose the hydraulically operated piston. An increase of pump suction pressure causes the piston to compress the spring, which in turn exerts pressure on the speed control rod. A drop in pressure reverses this procedure. Upward movement of the speed control rod causes an increase, and downward movement a decrease of the engine speed.

For hydraulic operation, the pressure valve is open and drain valve is closed.

Manual operation is accomplished by shutting off the hydraulic pressure and operating the manual adjusting wheel. The piston rests on bottom end of hydraulic cylinder and the adjusting wheel compresses governor speed changing spring to the desired engine speed. The small wheel above the manual adjusting wheel is used for locking the latter in any desired position.

Piston operated speed screw control. Fig. 4 shows a piston operated speed screw control for Woodward governor on a 1000-hp. engine.

Pump suction pressure forces piston upward and the gear rack turns the small inside engaging gear and the large outside gear. The large gear engages and rotates the small gear on the speeder screw extension shaft. Rotation of the extension shaft and speeder screw shaft are simultaneous as indicated in Fig. 4. The engine speed varies with the circular position of the speeder screw shaft. The stationary position of piston is fixed by the spring for any given pressure in the hydraulic cylinder. A corresponding circular position of the speeder screw shaft is taken for any fixed position of the piston. The total piston travel represents total rotary movement of the governor speeder screw shaft.

To disengage the hydraulic device the operator pushes in on the knob on outer end of speeder screw extension shaft. A spring actuated steel ball holds shaft in either "in" or "out" position as indicated in plan view of Fig. 4. When the hydraulic device is cut out the engine governor is operated manually.

Direct bellows operated control. Fig. 5 shows a direct bellows operated control for Woodward governor on a 250 hp. engine.

The sylphon bellows are installed inside of the hydraulic cylinder. Pump suction pressure on the closed upper end forces it down until the effective hydraulic force equals the combined opposing forces of the bellows, the bellows spring, and the governor speeder spring. The bellows push rod is attached to the upper inside end of bellows. The speeder spring push rod moves up and down through push rod guide bushing with upper end of speeder spring. Downward movement of upper end of bellows thus causes a corresponding movement of upper end of speeder spring and thereby compresses it permitting more fuel oil to be pumped to engine cylinders.

A decrease of hydraulic pressure in hydraulic cylinder permits bellows spring to force top end of bellows upward. The governor speeder spring expands a like amount, moving speeder spring push rod upward. The expansion of speeder spring permits governor to reset and reduce the engine speed. At constant hydraulic pressure, the engine speed is constant.

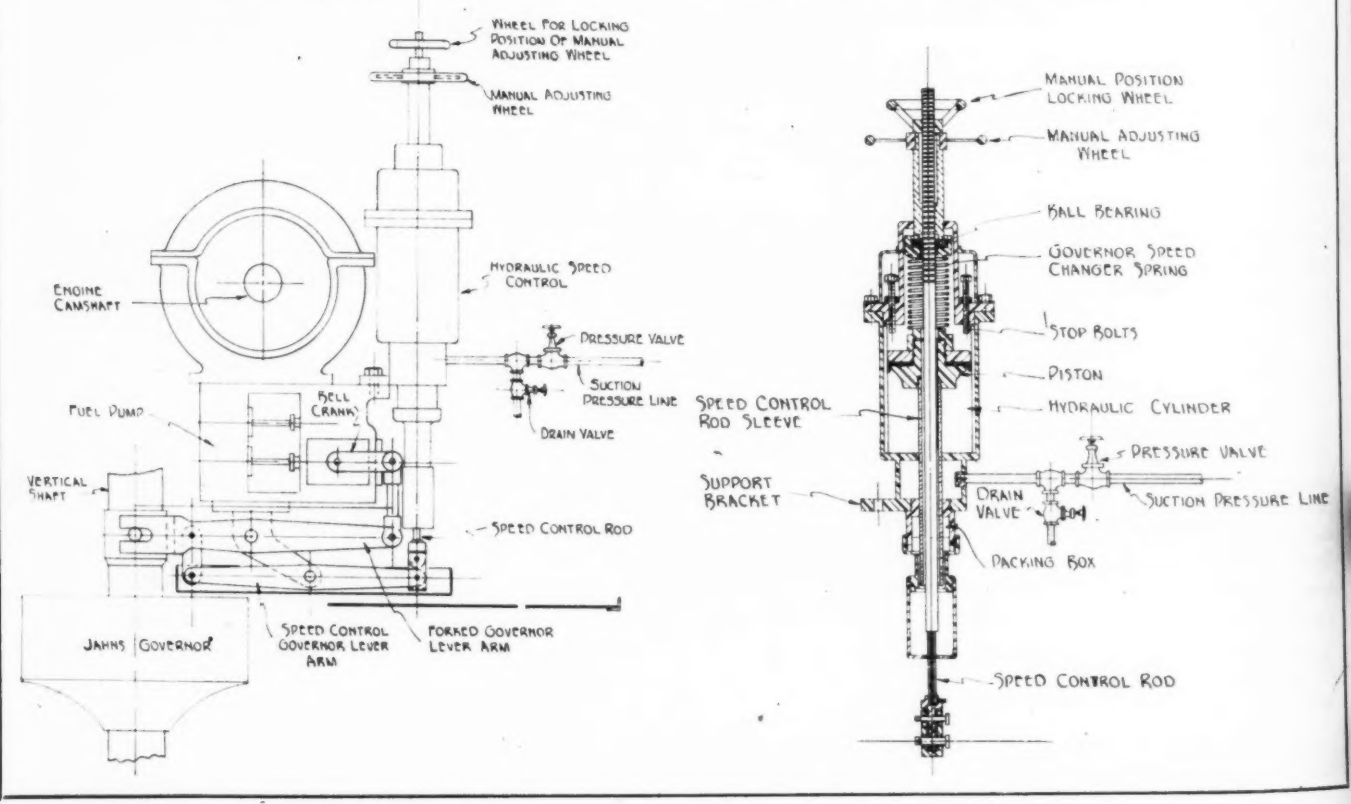
The pressure operating range may be altered by changing position of threaded adjustment nut. By screwing nut in, the bellows spring compresses to raise the pressure at which the hydraulic device operates. By screwing it out, the spring expands to lower it.

The locknut on speeder spring push rod acts as travel stop for the control. The push rod cap is also locked in position with a cotter pin as a safety precaution.

For manual control the pressure valve is closed and drain valve open. The knob on speeder screw shaft, shown in Fig. 5, is rotated by hand. The speeder screw shaft is connected through a gear train to the rack on one side of speeder spring cap. Downward movement of the cap compresses speeder spring for increasing the engine speed in same manner as described above for hydraulic operation.

Bellows operated pilot control. Fig. 6 shows a bellows operated pilot control for Woodward governor on a 730 hp. engine.

Figs. 2 and 3. Outline and sectional elevations of direct piston operated hydraulic control



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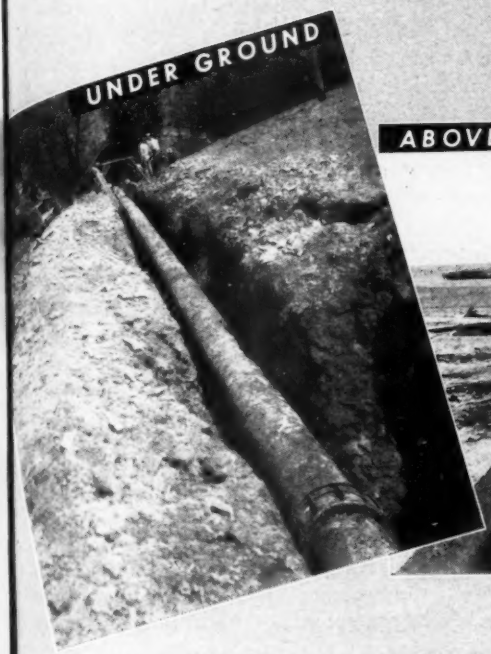

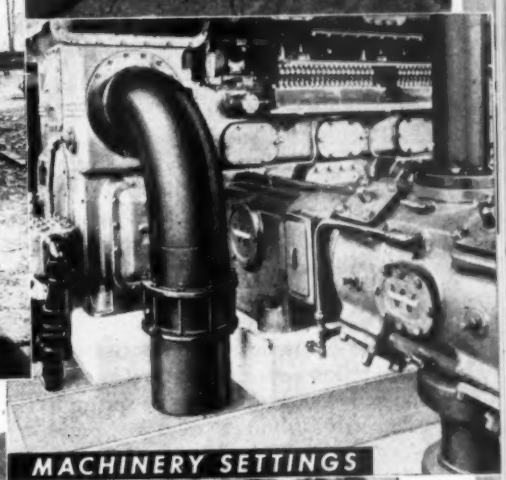

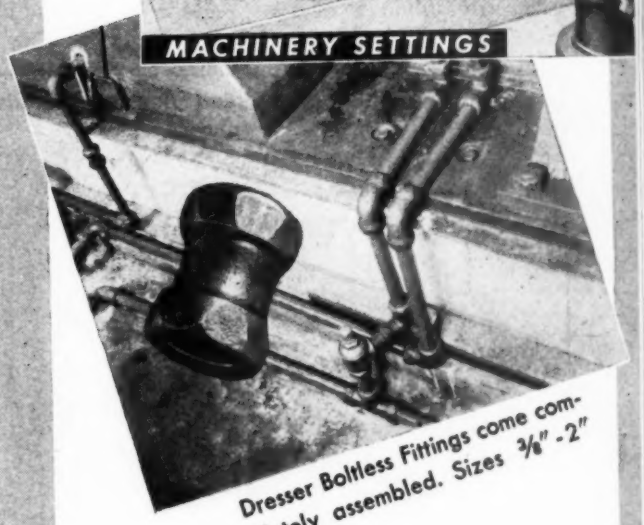

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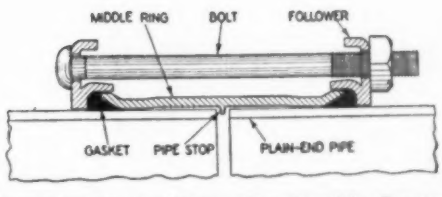

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Governor accumulator pressure is maintained around the lower small diameter of the differential piston. Movement of pilot valve plunger uncovers port in differential piston to admit or release pressure to or from upper large diameter. Downward movement admits pressure and upward movement releases pressure. Pressure differential causes identical vertical movement of pilot valve plunger and differential piston.

When pump suction pressure, in annulus surrounding the sylphon bellows, compresses bellows, the pilot valve plunger is forced downward by the pressure transmitted through push rod and push rod lever. This admits governor accumulator pressure to large diameter of differential piston. A reduction in pump suction pressure permits bellows spring pressure to expand the bellows, and pilot valve spring lifts pilot valve plunger, releasing pressure from large diameter of differential piston.

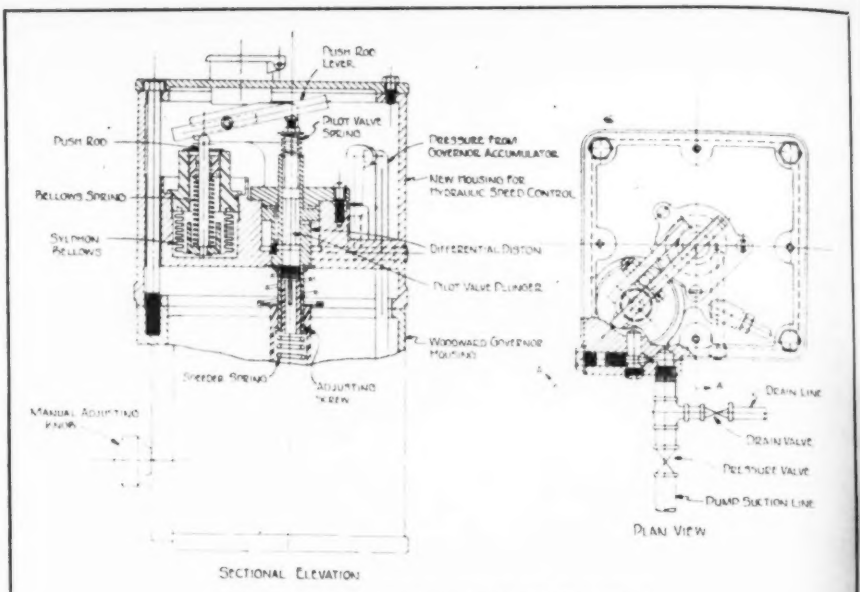


Fig. 6. Bellows operated pilot control

The speed control may be made inactive by increasing the engine speed by manual adjustment, to a value above that being maintained by the speed control while maintaining the desired pump suction pressure. To cut the speed control out of service for complete manual operation, the pump suction pressure is shut off and drain valve opened.

Results and conclusions. The following results have been obtained from combined use of hydraulic speed control and back pressure regulator valve:

(1) Reduced evaporation losses.

(2) Improved filling of pumps, thus permitting an increase of pump speed for providing additional capacity of present equipment.

(3) Permitted increase in velocity of oil in pump suction lines.

(4) Greater sensitivity of operation, i.e., leaks are more readily detected in lines with controlled suction pressure.

In some instances, at stations pumping to terminals, recording tachometers have been installed in conjunction with the hydraulic speed control that record engine speed variations. It also provides

Fig. 4. Piston operated speed screw control

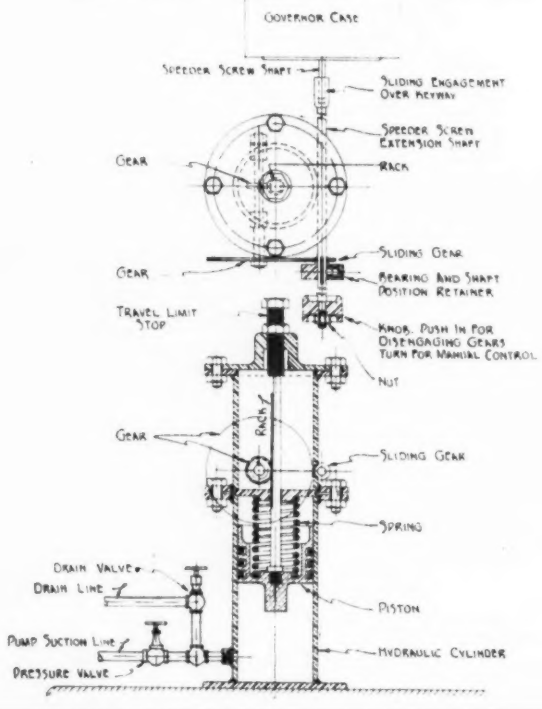
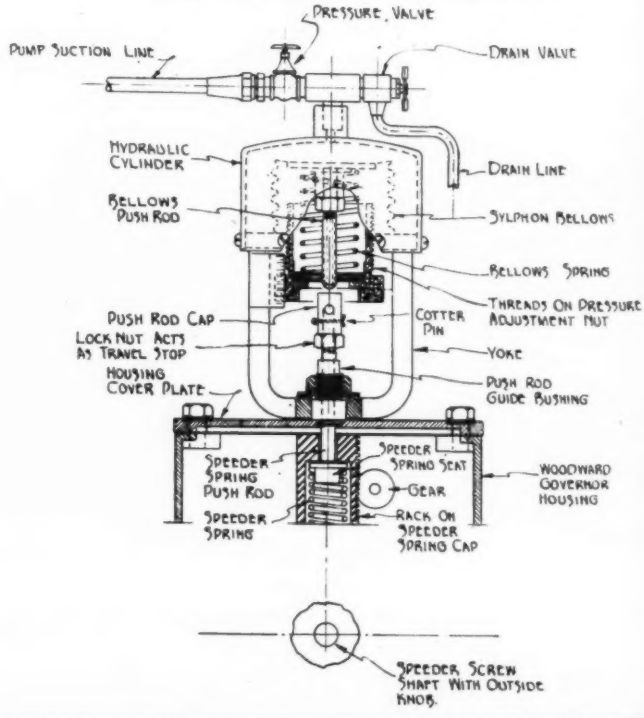
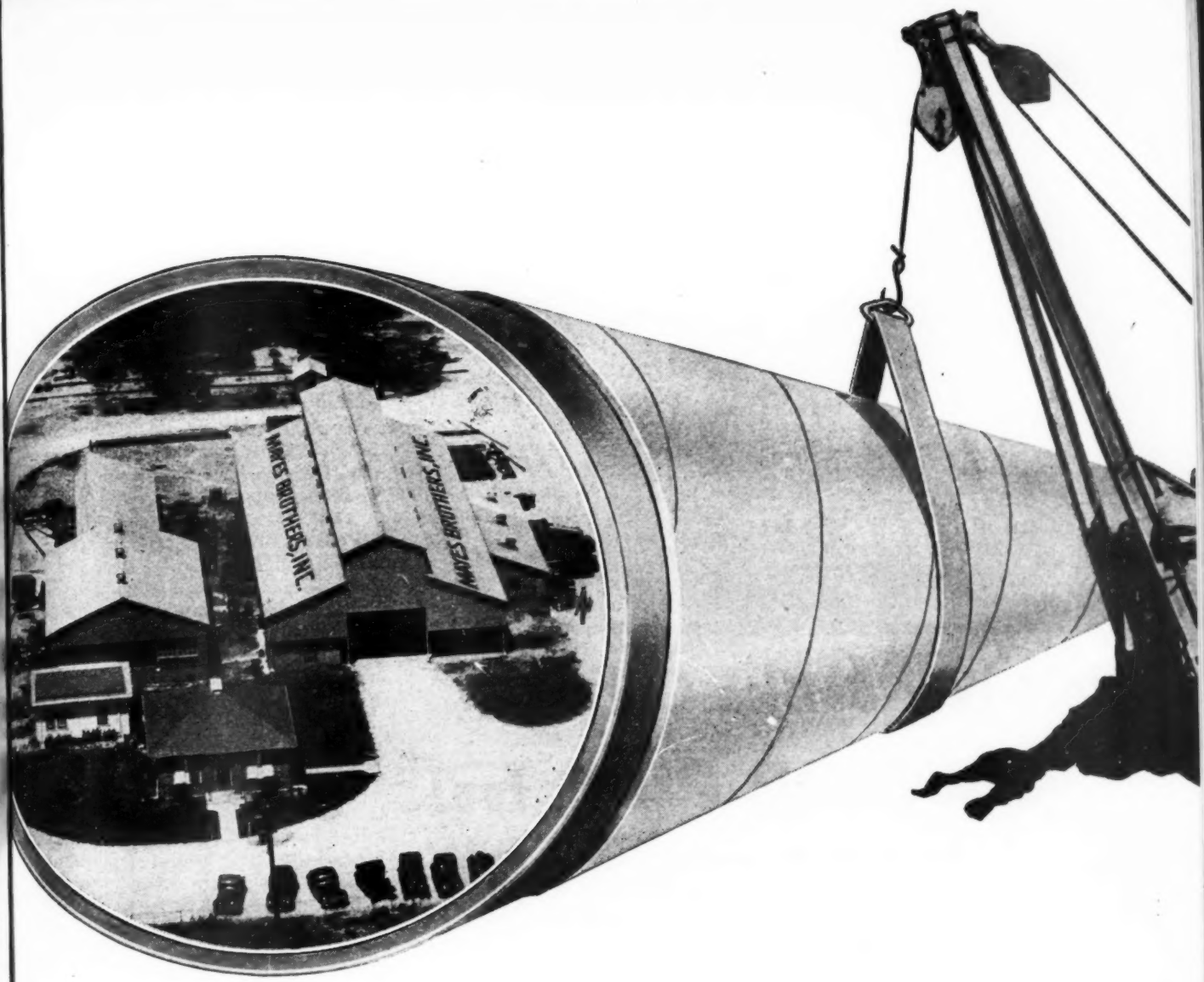


Fig. 5. Direct bellows operated control





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a record of engine operation and has proved valuable in determining the cause of pressure drop in discharge lines or any variation in deliveries at terminals.

Although no definite figures are available that show the savings resulting from the use of hydraulic speed control on pipe line pumping engines, it is believed, after 6 years of development and testing this principle at certain stations, that an appreciable reduction in evaporation losses has been effected. Our company has not made full use of the possibilities of hydraulic speed control; however, it is expected that the principle may eventually be used extensively, and it is our opinion that complete closed pumping systems for great distances are possible.

The author offers his apologies for having digressed in some instances from the main subject of diesel engines. However, it should be understood that the operating, maintenance, and control methods of diesel engines in pipe line service are so interrelated to many other pipe line engineering problems that it is difficult to cover thoroughly one subject without including some of the more closely related problems.

Acknowledgment. W. G. Heltzel and J. B. Harshman collaborated with the writer in development of this equipment. The writer also wishes to thank Mr. Harshman for helpful assistance in preparation of this paper.

C. C. Keane and F. E. Richardson built the first direct bellows type control for the Great Lakes Pipe Line Company.

The Woodward Governor Company manufactured the first bellows operated pilot control for the Stanolind Pipe Line Company.

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—Abstract from paper by Gordon N. Scott, National Association of Corrosion Engineers, Houston, Texas, April, 1944.

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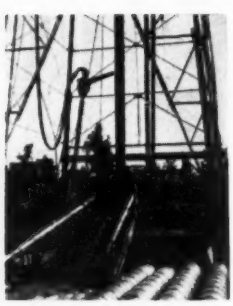

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By T. R. AUDE
Stanolind Pipe Line Company

INTERNAL corrosion of gasoline and products pipe lines first brings itself to notice by a reduction in the capacity. This reduction in capacity is principally caused by roughening of the pipe wall due to the formation of corrosion products. It is doubted that there is any appreciable decrease in the mean diameter of the pipe caused by the formation of corrosion products on the walls. This effect of internal corrosion is so important that the capacities of some lines handling gasoline have decreased 10 to 15 per cent within a few years. Most operators of products pipe lines now resort to scraping, the use of inhibitors, or both in an effort to counteract the effects of internal corrosion and maintain their lines at or near the original capacity. Another result of internal corrosion, perforation of the pipe wall causing leaks, may be equally important, but it does not occur so quickly. It will not be discussed herein.

The importance of the capacity losses which may result from internal corrosion, and their relation to the economical operation of products lines, makes it desirable to have some convenient means for expressing the condition or roughness of the line. Such a factor, to be most useful and universally applicable, should depend only on the condition of the line in question, and should not vary with any of the other factors entering into its operation.

The Hazen-Williams formula originally was developed by engineers for use when water was the flowing liquid. When so used, the factor C in this formula was a pure line-condition or roughness factor, as the viscosity of the liquid did not change (except slightly, due to temperature). This formula has withstood the test of years of use by engineers in designing water systems, and the handbooks contain reliable tables of average values of C for all types of pipe commonly used in water lines.

Many engineers have employed the Hazen-Williams formula successfully for designing pipe lines for the transportation of gasolines. It works very nicely as long as gasoline is the only product handled, inasmuch as the viscosity is fairly constant—although the values of C for gasoline differ from those for water in the same pipe. However, when products other than gasolines are to be transported by a products line, it is found that a different value of C must be employed for each different fluid. If, as is frequently the case, a single line contains slugs of several different products at the same time, it does not seem consistent to employ a formula which requires the use of a different C factor for each product when it is remembered that the factor C originally was intended to be a roughness factor, and is generally referred to as such.

The Fanning formula:

$$h = \frac{flv^2}{d2g} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (1)$$

Where:

h = head, in ft.,
f = friction factor,
l = length, in ft.,
v = velocity, in ft. per sec.,
d = diameter, in ft., and
g = acceleration due to gravity (32.2 ft. per sec. per sec.),

or its modification, has had wide application to the flow of many different fluids in tubes. As this formula is a mathematical expression of fundamental physical principles, it appears that, if properly evaluated, it should apply to any problem concerning the flow of fluids in pipes.

Converting this formula to more conventional pipeline units it becomes:

$$P = 34.837f \frac{B^2 s}{D^5} \quad . \quad . \quad . \quad . \quad . \quad (2)$$

Where:

P = friction loss, lb. per sq. in. per mile,
f = friction factor,
B = bbl. (42-gal.) per hr.,
s = specific gravity, and
D = inside diameter of pipe, in.

It has been shown by many investigators that the friction factor f in the foregoing formula is a function of the dimensionless expression $\frac{dvs}{u}$, commonly called the Reynold's Number and designated by the symbol R. Using the same conventional pipe-line units as in equation (2), this becomes

$$R = \frac{2212.OBs}{Du} \quad . \quad . \quad . \quad . \quad . \quad (3)$$

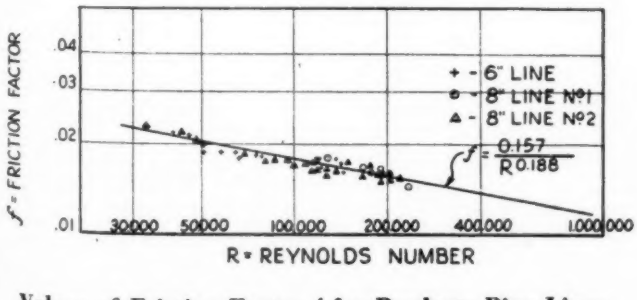
where: u = absolute viscosity in centipoises.

Heltzel[1] used Fanning's formula, equation (2), in his investigation of flow in crude oil pipe lines. He found that Stanton and Pannell's[2] data for smooth tubes yielded a curve for the relation $f = \phi R$, which checked very closely with actual conditions for crude oil in 8-in. and 12-in. commercial pipe.

The use of the Fanning formula in connection with a curve for values of f is somewhat cumbersome, particularly so when many problems must be solved. In order to construct charts and a slide rule for the more convenient solution of capacity problems, and to

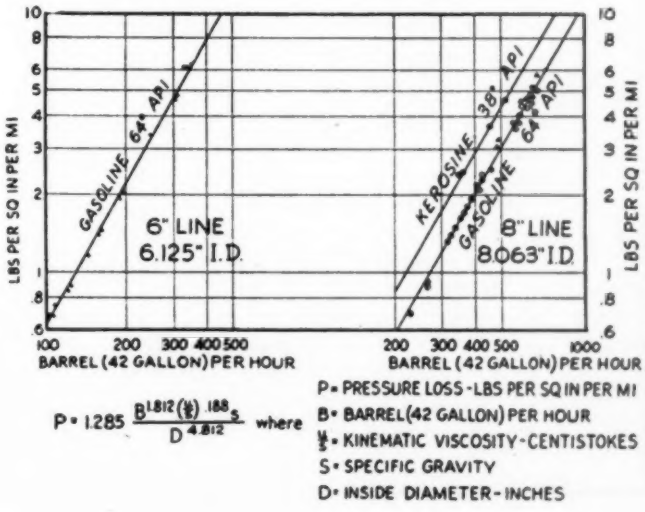
*Presented before American Petroleum Institute, Chicago, Illinois, November 9, 1943.

Fig. 1 (below)



Values of Friction Factor f for Products Pipe Lines.

Fig. 2 (right)



derive equivalent-length formulas for multiple parallel pipeline systems[3], it is necessary that some empirical relation be found for the expression $f = \phi R$.

Stanton and Pannell's data do not produce a straight line when f is plotted against values of R on double log paper. However, that portion of the curve, along which fall points representing most rates of flow in products lines, may be very closely approximated by the straight line whose equation is:

$$f = \frac{0.157}{R^{0.188}} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (4)$$

Fig. 1 shows a number of points representing actual operations of a 6-in. and two 8-in. lines handling refined products, and the line $f = \frac{0.157}{R^{0.188}}$.

Substituting the value of R from equation (3) in equation (4), it becomes:

$$f = 0.0369 u^{0.188} \frac{D^{0.188}}{B^{0.188}\, s^{0.188}} \quad . \quad (5)$$

Then, by substituting this value of f in Heltzel's form of the Fanning equation, the latter becomes:

$$P = 1.285 \frac{B^{1.812}\, u^{0.188}\, s^{0.812}}{D^{4.812}} \quad . \quad (6)$$

This is the equation derived by Heltzel[3] for flow in crude oil pipe lines for values of the Reynold's Number greater than 57,600. It has been found to correspond very closely to actual operation of new 6-in. and 8-in. lines handling refined products. Fig. 2 shows lines plotted from this equation for a 6-in. line handling 64-deg-A.P.I. gasoline, and an 8-in. line handling 64-deg-A.P.I. gasoline and 38-deg-A.P.I. kerosine. In Fig. 2 are also plotted points showing actual operations of these pipe lines. The fit is as good as could be expected.

Equation (6) should be used only for new products lines or those whose condition (capacity) is equal to new. It is suggested that any roughening of the pipe wall, in effect, would increase the values of the friction factor f in Fannings formula. I propose to introduce a line-condition factor, or roughness factor, K, to provide for changes in friction factor due to internal corrosion. For convenience, this factor will be introduced in such a manner that its value will be the ratio of the line capacity at any time to the capacity of the line when new. Equation (4) then becomes:

$$f = \frac{0.157}{K^{1.812}\, R^{0.188}} \quad . \quad . \quad . \quad . \quad (7)$$

Equation (5) becomes:

$$f = \frac{0.0369}{K^{1.812}} \frac{(u^{0.188})}{B^{0.188}\, s^{0.188}} \quad (8)$$

And equation (6) becomes:

$$P = \frac{1.285\, B^{1.812}\, u^{0.188}\, s^{0.812}}{K^{1.812}\, D^{4.812}} \quad . \quad (9)$$

The factor K would be 1 for new steel (smooth) pipe, and its value would decrease with increasing roughness. It may be possible to find a correlation between K and age of line for lines in which scrapers or inhibitors have not been used. In lines where scrapers or inhibitors are used, the value of K will have to be determined by experiment.

If we now solve equation (9) for B we get:

$$B = 0.871K \left(\frac{1}{u^{0.104}}\right)\left(\frac{P^{0.552}\, D^{2.656}}{S^{0.448}}\right) \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (10)$$

By substituting aC (a=a constant) for the term $0.871K$ in equation (10), we get:

$$B = aC \left(\frac{1}{u^{0.104}}\right)\left(\frac{P^{0.552}\, D^{2.656}}{S^{0.448}}\right) \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (11)$$

This equation is practically the same as the Hazen-Williams formula (expressed in the same units):

$$B = 0.00616C \frac{P^{0.54}\, D^{2.63}}{s^{0.54}} \quad . \quad (12)$$

except for the inclusion of the viscosity term: $\frac{1}{u^{0.104}}$ in equation (11). The small differences in the exponents in the two formulas will be of very little effect in the range of normal operations.

The use of the factor K as in equations (9) and (10) is recommended as being a fundamentally sound and convenient method for expressing the roughness of a pipe line as it affects capacity. K might be referred to as the "specific line-condition factor," as it is the ratio of the capacity of any pipe to the capacity of smooth pipe. For example, a pipe line which, when new, had a capacity of 10,000 bbl. per day but due to internal corrosion has had its capacity reduced to 9500 bbl. per day, would have a K factor of 0.95.

The introduction of a viscosity term in the Hazen-Williams formula, equation (12), would make that formula equally applicable. Then C would be a true roughness coefficient, and its values would be the same for any product.

Coupling Bonding on Gas Lines

In his fight against corrosion, the engineer in the natural gas industry has one problem that is not encountered in other industries. The major portion of natural gas lines are constructed with mechanical couplings having rubber gaskets, which occur every 20 to 40 ft. In the application of cathodic protection it is necessary that they be electrically bonded so that the pipe line is a continuous structure providing a low resistance metallic path in the pipe for the d-c. current return. — F. J. McElhatton, National Association of Corrosion Engineers, Houston, Texas, April, 1944.

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3. "Derivation of Equivalent-Length Formulas for Multiple Parallel Oil Pipe-Line Systems," W. G. Heltzel, *Oil Gas J.* 32 [51] 70 (1934).

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Cracking With Catalysts*

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IT is the purpose of this paper to discuss some of the fundamental principles of cracking catalysts and the catalytic cracking process, to give typical results over rather wide ranges of operating conditions and charging stock quality, give a brief description of present commercial designs of the fluid catalyst units, and point out some of the contributions of the Universal Oil Products Company to the process as it is now known.

In its simplest form, catalytic cracking requires a catalyst and some means for contacting the oil with the catalyst. During the reaction the catalyst becomes fouled with carbonaceous material, and this deposit is customarily removed by combustion. For a better understanding it is advisable to study the separate elements comprising catalyst cracking.

Catalysts. It seems certain that anhydrous aluminum chloride was the first catalyst used for cracking. The process employing this catalyst was developed by A. M. McAfee in 1913-15. The first catalytic cracking of the type known today may have occurred, in a minor way, incidental to clay treating. It is now generally known that many of the clays used for treating have some cracking activity. Of these clays one type, known as bentonite, forms active catalysts after having been treated with an acid. Montmorillonite, a nonswelling bentonite, has been used widely after acid treating.[1] Montmorillonite is a hydrosilicate of aluminum with a well defined crystal structure; it has the idealized composition of $Al_2O_3 \cdot 4SiO_2 \cdot xH_2O$. Usually the montmorillonite occurs with some of the alumina replaced by other oxides, such as magnesium oxide or iron oxide. If the catalyst is heated to about 1200°F. or higher, changes take place in the crystal structure, so that the catalytic activity is lost.

The pioneering research on catalytic cracking embodied intensive investigations and tests of the different types of catalysts—natural and synthetic. The limitations of the natural clay catalysts emphasized the many potential advantages of a manufactured catalyst. Early research, conducted by Hans Tropsch,[2] laid the foundation and led the way for those who followed. After his death, his associates discovered many additional synthetic catalysts, including the silica-alumina types. Further, they found that, when these are suitably prepared, they are more stable at high temperatures and more active than catalysts from natural sources. In the course of this development certain fundamental principles were discovered: [3, 4]

1. The silica and the alumina should be prepared in a hydrated form by precipitation or gel formation.
2. The hydrated silica and hydrated alumina could be precipitated either together or separately and then blended.
3. The finished catalyst should be substantially free from soluble metal compounds. Because the catalyst was ordinarily prepared from water glass (sodium of potassium silicates), special washing methods were developed to purify to the proper extent.

We believe that every truly synthetic cracking catalyst now used in the aviation gasoline program embodies in the method of its manufacture the foregoing basic principles.

Synthetic silica-alumina catalyst was selected for use in commercial fluid catalytic cracking units. The UOP type "A" catalyst, which is now in commercial production, is completely synthetic silica-alumina especially prepared for fluid units. Under Universal test conditions it has a higher activity than any of the natural silicate catalysts, and it is more stable at high temperatures. The superiority of the synthetic catalyst over natural catalysts is perhaps best illustrated by a test that applied to the commercially produced catalyst as a quality control. The catalyst is heated to 1650° F. for 6 hr. and then tested for activity; at least 50 per cent activity must remain after this test. Natural catalyst thus tested was reduced to 0 per cent activity.

Life tests were also made on the UOP type "A" catalyst in which the temperature of the catalyst was allowed to rise to 1300°F. during each regeneration for 12 regenerations each day for 300 days. During this period more than 300 gal. of catalytically cracked gasoline were produced for each pound of catalyst.

These tests emphasize the ruggedness of the type "A" catalyst. But even after methods had been found for obtaining such stability on catalyst produced in the laboratory, there remained the problems of commercial manufacture. Methods for controlling the precipitation and for washing the product had to be worked out. Both the American Cyanamid and Chemical Company and the Chicago Chemical Company cooperated in the solution of these problems. Each company now operates a commercial catalyst manufacturing plant built on the basis of this work, and the catalyst is made according to UOP specifications. Samples frequently are tested by Universal to insure the quality.

What makes the synthetic silica-alumina a cracking catalyst? So far only part of the answer is known. Each particle of catalyst is highly porous and these pores are extremely small. Large surfaces are required to form the walls of these small pores; therefore, a single pound of good cracking catalyst has approximately 50 acres of such surface. It is also known that without this surface the white powder ceases to be a catalyst, even though the chemical composition remains unchanged. Strictly speaking, instead of tons of catalyst being made each day, actually millions of acres of cracking catalyst surface are produced.

The catalysts derived from natural clays also have large surfaces. If both natural montmorillonite catalysts and the synthetic catalyst are comprised of silica and alumina, what is the difference between them? Is the synthetic catalyst more active and more stable just because it is purer? The available evidence seems conclusive that the two catalysts are quite different. According to X-ray diffraction results, the natural catalysts are crystalline whereas the synthetic catalyst is amorphous. The results obtained when cracking with the two catalysts are different. For a given gas oil consumption, the natural catalysts produce more gasoline and less gas than the synthetic silica-alumina. At the same time the gasoline produced by natural catalysts is more olefinic and less aromatic than that produced by the synthetic catalyst under comparable conditions. The synthetic catalyst, although more expensive, is very much superior to the natural catalyst for the production of aviation base stock because of the low olefinic and high aromatic content of the gasoline.

Contacting oil with catalytists. When oil vapors are contacted with either natural or synthetic catalysts, a portion of the oil is converted into other products. The extent of the conversion is dependent upon the operating conditions used.

Effect of process variables on conversion. The most obvious method of contacting oil with catalyst is to pass oil vapors through a fixed bed of catalyst. The variables in such an operation are: (1) temperature; (2) pressure; (3) the quantity of oil charged per unit of time per unit of catalyst (space velocity), and (4) the length of time

* Presented before American Petroleum Institute, Chicago, Illinois, November 10, 1943.

the oil is passed through the bed before regeneration (process period). The process variables and their effects on conversion of the charging stock may be summarized as follows:

1. *Temperature:* An increase in temperature increases the conversion. The usual temperatures are in the range of 600 to 1100 °F.

2. *Pressure:* An increase in system pressure results in an increase of conversion. Usual pressure ranges are atmospheric to 100 lb. per sq. in.

3. *Space velocity:* A decrease in space velocity increases conversion. Two definitions of space velocity are common: liquid hourly space velocity —the ratio of the volume of the oil charged per hour to the volume of the catalyst in the reactor; and weight hourly space velocity—the ratio of the weight of the oil charged per hour to the weight of the catalyst in the reactor. Usual space velocities are 0.1 to 10.

4. *Process period:* A decrease in the length of the process period serves to increase conversion. The process period may be as short as one minute and as long as several hours.

In the fluid catalytic cracking process the conversion of oil into other products is dependent upon these same variables. The definition of weight hourly space velocity is, just as previously, the weight of oil charged per hour per weight of catalyst in the reaction zone. The weight of catalyst in the reaction zone remains constant, although there is a continuous flow of regenerated catalyst entering the reactor and spent catalyst leaving it. From the rate of flow of catalyst to the reactor and the weight of the catalyst in that vessel, it is possible to calculate the average residence time of a particle of catalyst in the reaction zone. This average catalyst residence time is closely analogous to the process period of the fixed bed.

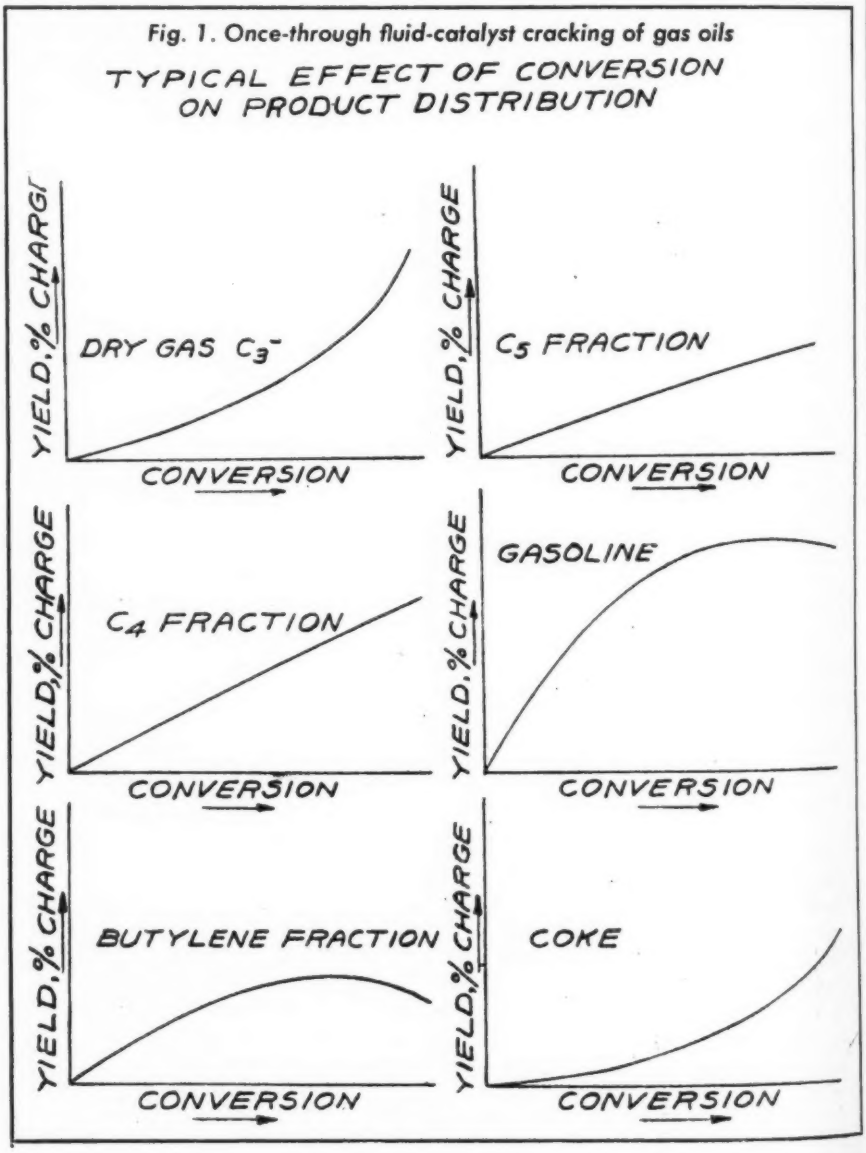
In the fluid process it is convenient to use the concept of catalyst-oil ratio, which is defined as the ratio of the weight of catalyst entering the reactor per hour to the weight of oil charged per hour. From the units of the three quantities—weight hourly space velocity, residence time of the catalyst, and catalyst-oil ratio—it is found that their product is equal to unity. From this fact it follows that, at constant weight hourly space velocity, an increased catalyst-oil ratio corresponds to a shorter residence time of the catalyst and, hence, results in an increased conversion.

An increase in conversion, therefore, can be obtained by: (1) a higher temperature; (2) a higher pressure; (3) a lower space velocity; and (4) a higher catalyst-oil ratio.

Product distribution in once-through fluid catalytic cracking. The next information necessary for an understanding of catalytic cracking has been called *product distribution*, i.e., the relative yields of various hydrocarbon fractions at any given conversion level. It has been found that the most important factors affecting product distribution are type of the catalyst, the conversion level, the temperature, and the quality of the charging stock. The influence of the nature of the catalyst has already been discussed. Inasmuch as only synthetic catalysts are to be used in fluid units for aviation gasoline production, the present discussion will be limited to UOP type "A" catalyst.

The effect of the conversion level on product distribution is shown graphically in Fig. 1. In these curves the term "conversion" is used in a general sense to mean the degree to which the cracking reactions have proceeded. "Conversion" may be expressed quantitatively as gas oil disappearance, as the yield of gasoline and gas or, preferably in some instances, as the yield of C_5 plus lighter hydrocarbons. As shown in Fig. 1, the production of dry gas (C_3 and lighter) increases continuously at an accelerating rate with increased conversion. The yields of C_4 and C_5 fractions increase in a more nearly linear manner. Because the C_4 fraction becomes more saturated as conversion is increased, there is a maximum yield of butylenes that can be obtained at a given temperature from any particular charging stock. The curve showing the yield of gasoline also passes through a maximum, and, in the region of decreasing yield beyond the maximum, "overcracking" is said to be taking place. Like dry gas, the production of coke (the carbonaceous material deposited on the catalyst) increases rapidly with increased conversion. The curves of Fig. 1 are purely diagrammatic, and are intended only to show the general nature of the relation between the conversion level and the yield of some of the products; but in

Fig. 1. Once-through fluid-catalyst cracking of gas oils



columns "A," "B," and "C" of Table 1 data are given which show quantitatively some of the effects discussed hereinbefore.

If conversion is held constant, an increase in temperature results in an increase in the production of dry gas and a decrease in the yield of C_5, the yield of gasoline, and the production of carbon. There is evidence that, for stocks of low characterization factor,* the effect of temperature on the yield of gasoline is minimized and may be reversed. The effect of temperature on the yield of total C_4's at constant conversion is relatively minor. The results shown in columns "D," "F," and "G" of Table 1 indicate the differences involved.

In going from a naphthenic to a paraffinic gas oil at a constant conversion level and temperature, a decrease in gasoline yield and a decrease in coke production are obtained. The data given in columns B, D and E of Table 1 serve to illustrate these effects.

Product quality in once-through fluid catalytic cracking. "Product quality" in catalytic cracking can be considered an extension of product distribution, because it depends upon the relative yields of the different types of hydrocarbons in a given boiling range, i.e., the proportions of paraffinic, olefinic, naphthenic, and aromatic hydrocarbons in each fraction. In general, the same factors affect product quality that influence product distribution, viz., type of catalyst, conversion level, temperature, and quality of the charging stock.

The data given in Table 1 aid in understanding the effects of each of these variables. An increase in conversion in a given temperature range tends to reduce the olefin content of all the products. In the case of the C_4 and C_5 fractions, the decrease in olefin content is accompanied by increases in the proportions of isobutane and isopentane. It is interesting to note that the concentrations of n-butane and n-pentane remain relatively constant at about 5 to 10 per cent by volume of the C_4 and C_5 fractions, respectively, over the entire range of temperatures and conversion levels normally encountered. The decreased olefin content of the gasoline fraction at higher conversions is accompanied by an increased aromatic content, and these changes together result in superior leaded antiknock ratings at higher conversions. The fraction boiling just above aviation gasoline and below the initial boiling point of the charge (normally 340 to 400 °F.) is called heavy naphtha, and is characterized by a relatively low degree of unsaturation — usually with a bromine number less than 10, and a high aromatic content that amounts to 80 to 90 per cent at high conversions. This material ordinarily is blended into motor fuel, for which it has excellent proper-

*Referred to herein as "characterization factor K; see reference (5).

TABLE 1
Typical once-through fluid catalytic cracking results

Column	A		B		C		D		E		F		G	
Charging stock:	Gas oil (400 to 725 °F.)													
Gravity, deg. A.P.I. at 60 °F	25.2		25.2		25.2									
UOP characterization factor K^5	11.2		11.2		11.2		11.7		12.2		11.7		11.7	
Temperature	High										Intermediate		Low	
Conversion:														
Per cent by weight of C_5 and lighter	15.0		25.0		35.0		25.0		25.0		25.0		25.0	
100—per cent by volume of recycle stock (400 °F.+)	46.1		65.3		75.9		56.0		46.4		58.4		60.7	
	Per cent by weight	Per cent by volume	Per cent by weight	Per cent by volume	Per cent by weight	Per cent by volume	Per cent by weight	Per cent by volume	Per cent by weight	Per cent by volume	Per cent by weight	Per cent by volume	Per cent by weight	Per cent by volume
Yields, per cent of charge:														
Dry gas, C_3 and lighter	6.0	....	10.1	....	14.5	....	9.5	....	7.7	....	7.5	....	4.9	....
C_4 fraction	5.6	8.6	9.4	14.4	12.8	19.7	9.4	13.8	9.2	13.0	10.0	14.7	10.9	16.0
C_5 fraction	3.4	4.9	5.5	7.9	7.7	11.0	6.1	8.3	8.1	10.7	7.5	10.3	9.2	12.6
Depentanized gasoline, C_6 at 400 °F	28.0	30.9	34.5	37.9	30.2	33.2	25.9	28.2	19.4	20.8	27.5	29.8	27.1	29.3
Recycle stock, 400 °F+	54.9	53.9	35.8	34.7	25.1	24.1	45.1	44.0	54.4	53.6	42.6	41.6	40.2	39.3
Catalyst carbon	2.1	....	4.7	....	9.7	....	3.9	....	1.2	....	4.9	....	7.7	....
Total	100.0	98.3	100.0	94.9	100.0	88.0	100.0	94.3	100.0	98.1	100.0	96.4	100.0	97.2
Product quality:														
Dry gas, C_3 and lighter:														
Mol per cent H_2	12		13		13		12		10		7		4	
CH_4	21		23		25		21		20		15		18	
C_2H_4	11		8		6		10		12		8		6	
C_2H_6	7		9		11		7		3		8		7	
C_3H_6	29		21		12		35		51		34		28	
C_3H_8	20		26		33		15		4		28		37	
Total	100		100		100		100		100		100		100	
C_4 fraction:														
Liquid, per cent by volume of:														
iC_4H_8	14		11		6		17		22		7		3	
nC_4H_8—1	15		11		6		17		22		7		3	
nC_4H_8—2	6		7		7		8		11		14		11	
iC_4H_{10}	55		61		71		48		35		62		73	
nC_4H_{10}	10		10		10		10		10		10		10	
Total	100		100		100		100		100		100		100	
C_5 fraction:														
Liquid, per cent by volume of:														
C_5H_{10}	45		37		26		49		58		31		19	
iC_5H_{12}	47		55		66		43		34		61		73	
nC_5H_{12}	8		8		8		8		8		8		8	
Total	100		100		100		100		100		100		100	
Depentanized aviation-base stock, C_6 at 340 °F.:														
Gravity, deg. A.P.I. at 60 °F	52		47		42		50		55		50		50	
Bromine No.	34		25		20		42		59		28		13	
Aromatics, per cent by weight	40		60		75		42		28		42		42	
Octane No., 1-C plus 4.0 ml. TEL per gal.	90.8		(94)		(97)		89.8		(88)		92.3		94.2	
Heavy naphtha, 340 to 400 °F.:														
Gravity, deg. A.P.I. at 60 °F	30.8		29.6		27.7		33.5		33.4		32.1		33.2	
UOP characterization factor K	10.79		10.68		10.56		10.95		10.95		10.88		10.94	
Aromatics, per cent by weight	67		73		81		69		80		67		69	
ASTM Octane No.:														
Without addition of TEL	87.7		90.0		90.5		83.0		83.7		85.0		83.3	
Plus 3.0 ml. TEL per gal	90.5		91.5		91.7		87.2		87.3		86.6		87.4	
Recycle stock, 400 °F.+:														
Gravity, deg. A.P.I. at 60 °F	22.7		20.3		19.2		28.7		36.9		28.5		28.5	
UOP characterization factor K	10.84		10.70		10.65		11.37		11.83		11.26		11.27	

ties; but extensive work is being done at the present time in an effort to convert as much of it as possible into the boiling range of aviation gasoline. The API gravity and the characterization factor of the recycle stock (400 °F+) decrease markedly with increased conversion.

An increase in the characterization factor of the charging stock at a given conversion level and temperature results in an increase in the unsaturation of all the products. There is an accompanying decrease in the isoparaffin content of the C_4 and C_5 fractions, and in the aromatic content of the aviation gasoline. The effect of the quality of the charging stock on the aromatic content of the heavy naphtha fraction is small.

The effect of increasing temperature at constant conversion is to increase the methane and hydrogen content of the dry gas and to increase the olefin content of all fractions. There is a minor tendency for the aromatic content of the gasoline and naphtha fractions to be increased by high temperature operation.

Catalytic cracking of lighter and heavier stocks. The foregoing discussion has been limited to typical gas oils boiling approximately between 400 and 750 °F. If a stock with an appreciably lower average boiling point, a kerosine for example, is catalytically cracked, the following differences in results are found: 1. The stock is more refractory, i.e., more severe processing conditions are required to realize a given conversion level. 2. The products are less olefinic than those from a typical gas oil. The gaseous fractions contain more isoparaffins, and the liquid fractions are more aromatic. 3. There are only minor deviations from the product-distribution curves discussed hereinbefore unless the initial boiling range of the charge is in the boiling range of the products.

Conversely, heavier stocks are more easily cracked and yield more unsaturated products. Thus it is possible to vary the conversion and quality of products obtainable from a given unit over wide ranges by proper selection of the boiling range of the charging stock. Of great interest in the postwar operation of fluid catalytic units is the possible cracking of topped and reduced crudes without preliminary flashing.

Recycle operation in fluid catalytic cracking. It is well known that in thermal cracking a higher yield of gasoline can be obtained in a recycle operation than in a once-through operation. It was shown in Universal pilot plants using synthetic catalysts[6] that this same effect holds in catalytic cracking, and that the yield of gasoline can be increased by a recycle operation. Furthermore, it is usually possible to realize the increased yield of gasoline with a more favorable gasoline-to-carbon ratio. In commercial practice, however, it is generally true that, although higher *yields* can be realized by a recycle operation, higher *production* from a given plant is possible in a once-through process. A comparison of typical yields from a once-through and a recycle operation is given in Table 2.

Finishing. Present aviation gasoline specifications are such that base stocks of high quality must be relatively low in olefin content and high in aromatic content. These requirements can be met in fluid catalytic plants in two ways: first, the unit may be operated at relatively low temperatures (800 to 900 °F.), in which case a base stock having a low bromine number and the necessary high lead susceptibility is produced. However, conversions high enough to correspond to the desired aromatic content are difficult in such an operation on most stocks because of the severity of other operating conditions necessary, and because of relatively high production rates of carbon at the lower temperatures. As an alternative, the cracking operation can be carried out at higher temperatures and higher conversions. This operation produces a base stock which is rich in aromatics but which, unless unusually high conversions and low characterization-factor stocks are used, contains a higher quantity of olefins than can be tolerated directly in aviation-base stocks. Accordingly, some method of treating this gasoline must be employed.

It was found that, when the gasoline from high-temperature catalytic cracking is contacted with a synthetic silica-alumina catalyst[7] in the temperature range of about 700 to 900° F., a base stock of exceptionally high quality is produced. Not only is the olefin content reduced but other changes in the composition of the gasoline also take place resulting in a marked improvement in quality. This operation is highly desirable in many instances, particularly when paraffinic charging stocks are processed. However, the equipment for fluid catalytic treating can be employed for additional gas oil cracking, so that the desirability of fluid catalytic treating depends upon a balance between the production rate and the quality of the base stock, as well as upon other factors which necessitate a separate evaluation of each refinery situation.

A second method of removing olefins from gasolines is sulphuric acid treatment. The removal of the olefins and, in the case of high sulphur stocks, the simultaneous desulphurization realized result in marked improvement in lead susceptibility (hence, leaded octane number). However, the rearrangement of the other components of the gasoline through fluid catalytic treating is not realized, and the improvement in quality is inferior to that obtained in the catalytic treating step. This differ-

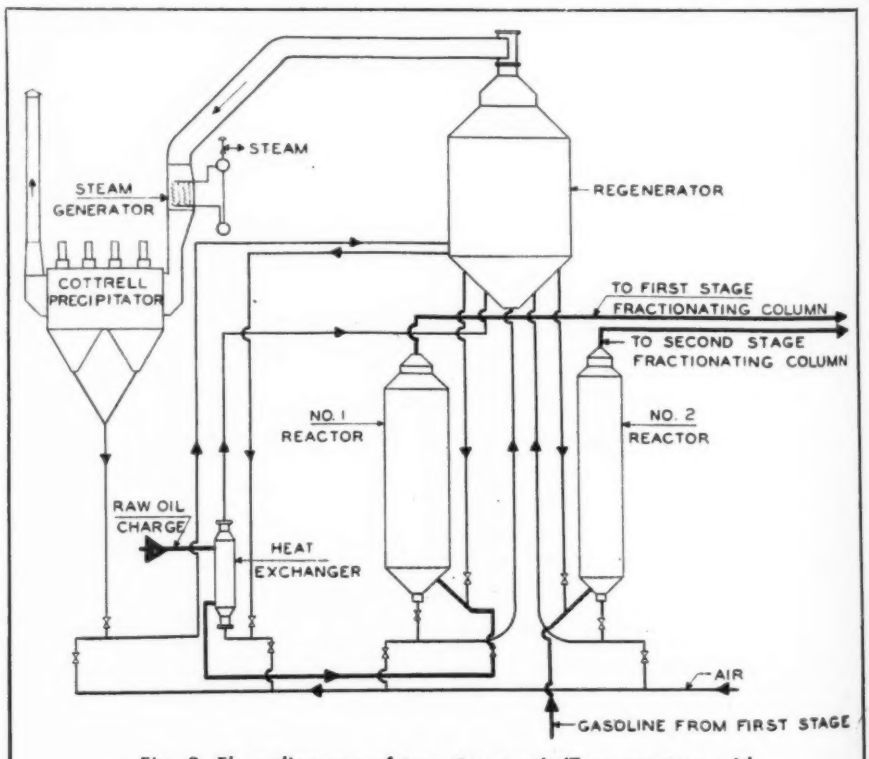


Fig. 2. Flow diagram of two-stage unit (Two reactors with common regenerator)

ence in quality is offset in part by a considerable reduction in the amount of equipment required, and can be minimized further by the operation of the first-stage cracking step at higher conversion levels. Accompanying the acid treatment, of course, is a loss of hydrocarbons and an appreciable consumption of acid.

A third finishing method is a relatively new Universal development known as "polytreating." This operation comprises liquid-phase treatment of the gasoline in the presence of a UOP solid catalyst. The results are comparable with those which can be realized by sulphuric treatment, because the principal reaction in both processes is the removal of olefins. The improvement in quality is, therefore, largely a result of the improved lead susceptibility resulting from removal of the olefinic compounds. A prime feature of this process is the long life of the catalyst, which makes it economically attractive. The high-boiling material produced in this operation is quite satisfactory for catalytic recracking; thus the volumetric loss of aviation fraction attending the polytreating operation itself is not chargeable against the combined catalytic cracking and treating operation, as a large part of the bottoms can be recovered as aviation gasoline in the recracking step.

Present wartime restrictions preclude a tabulation showing the antiknock quality of the base stocks, but it may be stated that fluid catalytic treating produces base stock of a quality not approached by the other treating methods.

Regeneration. The catalytic cracking and treating process would be extremely simple if it were not for the fact that during processing a carbonaceous deposit forms on the surface of the catalyst. This deposit seriously impairs the effectiveness of the catalyst, and makes necessary its periodic regeneration. Thus, the problems of minimizing the production of the deposit and of removing it without permanently damaging the activity of the catalyst are of major concern.

From fundamental studies it was learned that excessive temperatures are detrimental to the activity of the catalyst. And yet high temperatures are practically synonymous with regeneration, because the latter is accomplished by combustion of the carbonaceous deposits. When the problem of regeneration in a fixed-bed of catalyst is examined, it soon becomes apparent that combustion with air without cooling is, in most cases, not possible without subjecting the catalyst to such temperatures in the burning wave that its catalytic activity is soon destroyed. The most common expedients for controlling this temperature are dilution of the regeneration air with inert gases and provision for internal cooling.

In the regeneration of fluid catalyst the problem is the same—extremes of temperature must be avoided. The turbulence and constant circulation of the particles of catalyst make it impossible to build up appreciable temperature gradients in the regenerator or to realize the burning-waves characteristic of regeneration in a fixed bed. This same condition in the regenerator also permits the use of undiluted air without preheating.

Commercial fluid catalytic cracking units. The basic type of commercial fluid catalytic cracking unit, the so-called "single-stage" unit, consists fundamentally of a regenerator and single reactor. When it is desirable to treat by means of fluid catalysts the gasoline made on a single-stage unit, it is necessary to resort to a "blocked-out" operation — in which gasoline is produced for a few days, then treated in the same equipment. Although this type of operation is feasible, it has the disadvantages of lower calendar-day throughput, of increased tankage requirements, and of the necessity of changes in operating conditions while the unit is onstream.

The "two-stage" unit, which simultaneously cracks raw oil to gasoline and treats this gasoline to make a finished base stock, avoids these difficulties. The two-stage unit consists of two reactors with a common regenerator, each reactor running under the optimum conditions for the task it is performing. Inasmuch as the two-stage unit can be run with both reactors on cracking, if desired, it offers a wide range of operating flexibility and control of the quality of the product.

A simplified flow diagram of the reactor-regenerator section of a two-stage fluid catalytic cracking unit is shown in Fig. 2. Wartime restrictions have prevented the presentation of a detailed flow diagram. In the following description of the flow the equipment involved in cracking will be called "first-stage," whereas that on treating will be called "second-stage."

The raw oil charging stock, usually gas oil, is preheated by heat exchange with a recirculating stream on the first-stage fractionating column; it then goes to the catalyst-to-oil heat exchanger, where it receives further preheat from a stream of catalyst which circulates between the exchanger and the regenerator. The primary purpose of this heat exchanger is to give a wide degree of flexibility to the catalyst-to-oil ratio on the first stage. As there is a definite amount of heat to be removed from the regenerator, it is obvious that, when part of it is transferred in the heat exchanger, there will be less left to be transferred by the catalyst circulating between the regenerator and the reactor; thus a lower catalyst-to-oil ratio is permitted. Any additional heat required by the reactor is supplied by means of a fired tubular heater, in which the charge is heated further. The raw oil then enters the reactor riser, where it comes into contact with the hot regenerated catalyst flowing from the regenerator. The oil is now completely vaporized, and the catalyst is fluidized to a relatively light condition so that the mixture flows upward into the reactor. Usually, recirculated process gas or steam is injected into the reactor riser to aid in fluidizing the mixture.

The vapors leaving the reactor carry some of the catalyst fines with them. The major portion of these catalyst fines is recovered by passing the vapors through cyclone separators. The remainder of the fines is recovered as a slurry at the bottom of the fractionating column.

The products of the reaction are then fractionated in the first-stage fractionating column and gas-concentrating

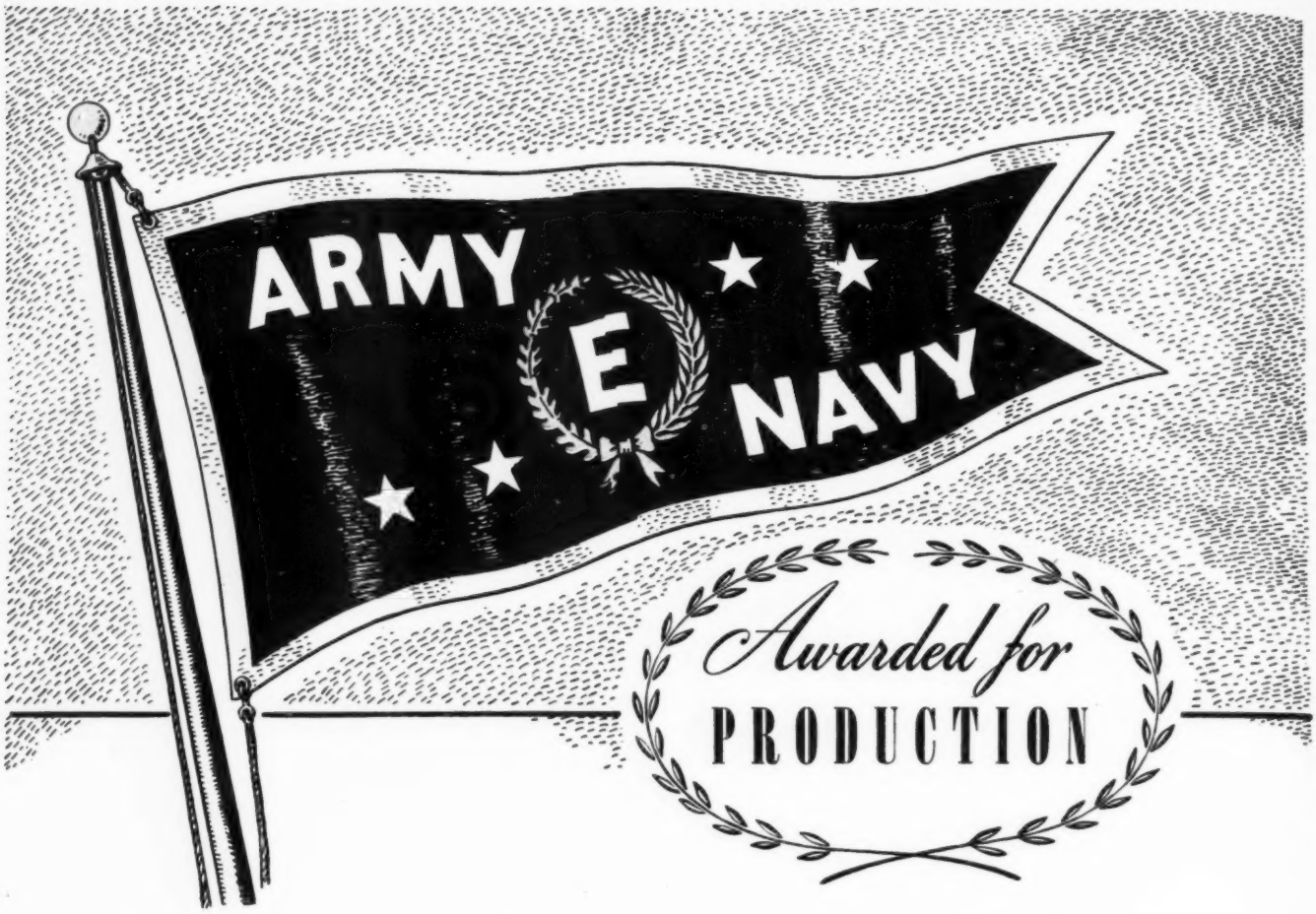
(Continued on Page 202)

TABLE 2

Comparison of once-through and recycle operations—fluid catalytic cracking

Operation	330 °F., once-through		334 °F., recycle*	
Charging stock	33-deg.-A.P.I., 11.7-K,† 400- to 725 °F. gas oil			
Temperature	High			
Combined feed ratio (total feed per fresh feed)	1.00		1.53	
Yields (per cent fresh feeds)	Per cent by weight	Per cent by volume	Per cent by weight	Per cent by volume
Dry gas, C_2	12.7	....	12.0	....
C_4 fraction	11.3	16.8	13.5	19.9
C_3 fraction	8.0	10.9	9.4	12.9
Depentanized C_4 at 400 °F	25.0	26.8	31.9	34.8
Recycle stock, 400 °F.+	37.8	36.9	27.7	26.7
Catalyst carbon	5.2	....	5.5	....
Total	100.0	91.4	100.0	94.3

*Total 400 °F.+recycle stock returned with fresh feed in amount indicated.
†UOP characterization factor.



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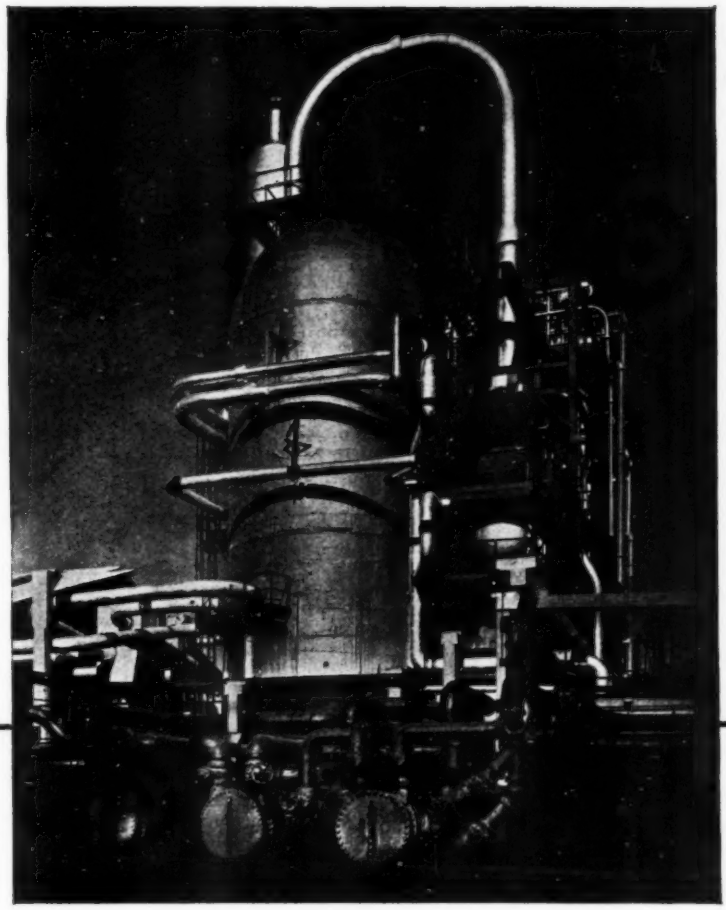

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(Continued from Page 199)

equipment, from which a gasoline cut is returned to the second-stage reactor for treating — usually at a somewhat lower space velocity and temperature. Heat is furnished to the second-stage reactor principally by hot catalyst from the regenerator, the catalyst-to-oil ratio in this stage being relatively high. From the second-stage reactor the treated product passes to the second-stage fractionating and gas-concentrating sections for separation.

The air required for combustion of the carbonaceous material on the spent catalyst enters at the base of the regenerator risers and carries the catalyst upward into the regenerator. As the regenerator is quite large — some regenerators being more than 40 ft. in diameter—a perforated plate is installed to insure even distribution.

The regenerated catalyst flows into the standpipes, down to the two reactors, and to the catalyst-to-oil heat exchanger. The material in the stand pipes is quite dense, so that the head developed is sufficient to cause the catalyst to flow into the reactors and heat exchanger—the flow rates being controlled by the slide valves. The products of combustion leave the regenerator through a cyclone separator, which removes the greater part of the entrained catalyst. The gases then go through a steam generator, which recovers a large part of the waste heat, and then through a Cottrell electrical precipitator, which recovers most of the remaining catalyst. From there the gases are discharged into the atmosphere.

Future of catalytic cracking. The demands of war have occasioned intensive study of internal-combustion engine design for greater power output, and new fuels have had to be developed for use in the new engines. Fortunately the petroleum industry was ready at the outbreak of war with new processes to produce such fuels. Catalytic cracking had been developed to such a point that it was possible to meet the stringent requirements of our armed forces.

There is no doubt that after the war automotive engine designers will incorporate many features of aircraft engine design in automobiles, and they will premise their designs on the availability of fuels of much higher quality than those which existed before the war.

There need be no apprehension on the part of the small refiner as to the utility and economy of adapting catalytic cracking to his refinery operations after the war. Although it is true that the cost of such installations may not seem attractive at this time, nevertheless the continued development and refinement of the process shows a progress which is most encouraging. It is a foregone conclusion that he will benefit greatly from the present activity of research and development in this art. The many large and costly commercial installations are the proving and developing grounds for refinements which will produce the plants of the future to fit the capacity and pocketbook of the small refiner. History has demonstrated that the processes will be available for his use. A new process, not fully developed, requires venture capital to prove or disprove it commercially. This risk is taken by the large refiners. The success and experiences are converted into profitable operation for small refineries so important to our national welfare and economic fabric.

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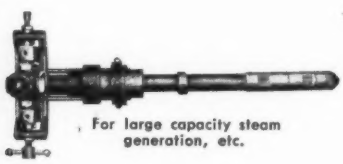

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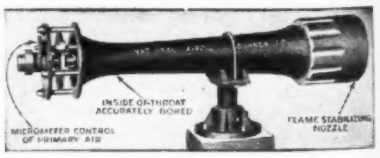

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Recent Developments in Houdry Fixed Bed Catalytic Processes*

By T. B. PRICKETT and R. H. NEWTON
Houdry Process Corporation

SEVEN years ago, after pioneering the development of catalytic cracking, the first commercial Houdry unit for the production of high octane gasoline was put into operation. By virtue of the quality of the products and the favorable economic factors of the process, catalytic cracking has become one of the leading processes used by the petroleum industry. The number of refiners sharing the Houdry static bed process has increased from two to nine, and the installed catalytic charging capacity has increased accordingly. In 1938, three units[1] processed a total of 20,000 bbl. per day. Now 20 units with individual capacities of 7,000 to 20,000 bbl. per day are in operation and nine additional static bed units are in various stages of construction.

Although detailed data concerning the production of aviation fuels have been made available for limited distribution, no specific information has been released generally by Houdry Process Corporation since the invasion of Poland. The purpose of this paper is to outline the more recent developments in as much detail as military secrecy permits.

Prior to World War II, Houdry Process Corporation realized that supplies of aviation gasoline in excess of the quantities generally predicted would be required in the event of hostilities of a major nature. Accordingly, this company instituted a research program, leading toward the development of methods that would permit increased production of aviaton base stock.

The first step in this program was the commercial production of previously developed synthetic catalysts which produced aviation base stock of more acceptable qualities than obtained from clay catalysts. In addition, the properties and action of these new catalysts could be controlled with precision, thus obviating reliance on naturally occurring clays of variable qualities. To insure that adequate catalyst supplies of the requisite characteristics always would be available to users of the process, plants for catalyst manufacture were built and operated by Houdry Process Corporation.

Simultaneously with the construction of the first synthetic catalyst plant started during 1939, a comprehensive laboratory program for the study of the production, properties, and composition of catalytically cracked aviation fuels was instituted. Over a period of years comparisons have been made between the laboratory and the operating plant data which demonstrate that the results obtained in the small scale units are duplicated in the commercial equipment. Therefore, these test units are being employed in forecasting operating conditions and yields for the commercial plants, and determining the product qualities that will be realized.

As the process development work progressed, it became apparent that the large quantities of aviation base stock believed to be required could not be produced from the available narrow boiling naphtha cuts heretofore considered as optimum charging stocks.[2] With this thought in mind, and also because a serious shortage in butylenes for alkylation appeared likely, it was realized that heavy cuts must be utilized for the production of aviation base stock. However, as the boiling range of the charging stocks increased, the cracked product tended to become less suitable for aviation fuel. During 1938, Socony-Vacuum Oil Company produced, on their Houdry unit at Paulsboro, New Jersey, a low acid-heat aviation base stock by catalytically treating the primary gasoline on clay catalyst. The Houdry Laboratory conducted an extensive research program and perfected the application of the procedure for the treating of gasolines produced from a large variety of virgin stocks by synthetic catalyst. The resulting two step process has been in commercial operation for nearly two years and has resulted in the production of large quantities of superior aviation base stock.

Wartime activities. Immediately following our entry into the war, the existing Houdry plants producing high quality motor fuels were converted as rapidly as possible to aviation base production. The quality improvement attained, due in no small part to the synthetic catalysts employed, was of prime importance in increasing the country's output of 100-octane aviation fuel, particularly during the critical first 6 months of the conflict. During this period the production of alkylate was small. The maximum supplies of finished aviation fuel were only obtainable by blending the minimum possible proportion of the scarce alkylate with the best quality base stocks produced—the output of 14 Houdry static bed plants. The fact that these Houdry plants were in successful commercial operation at that time contributed greatly to decreasing the aviation gasoline shortage. This can be disclosed now because of the vast expansion in alkylate production facilities since the period mentioned.

Another substantial contribution to the war effort by those refiners operating Houdry static bed plants was the production and recovery of isobutane and butylenes for the expanding alkylate industry. Previously the charge to alkylation units generally consisted of isobutane from natural gasoline plants and of butylenes recovered from thermal cracking units. The additional supplies of both these essential products from the Houdry plants materially increased alkylate production.

Catalyst manufacture. To convert the existing static bed plants to aviation production and to provide for the newly authorized Houdry units, the original synthetic catalyst plant, started in 1939, was doubled in capacity during 1941 and its production again doubled in the past year.

Commercial operations. In addition to improvements made in aviation base quality, there have been advances in plant operating techniques as well. By continued improvement in the mechanical features of the plants, including plant auxiliaries, onstream time efficiencies have been increased to about 90 per cent. Houdry efficiencies are comparable therefore to those obtainable on general refinery processing equipment.

For example, one 20,000-bbl.-per-day plant processed a total of 9,000,000 bbl. of gas oil over a period of 17 months during which the plant was on stream 87 per cent of the elapsed time, which includes the time required to change catalyst at the end of the period. After the change of catalyst this plant was operated above rated capacity for 375 days to satisfy the emergency demand for fighting grade aviation fuel. During this period the onstream time efficiency was maintained at 95 per cent, including the ensuing second catalyst change and a general inspection and overhaul. After this second catalyst change a careful survey showed that

*Presented before American Petroleum Institute, Chicago, Illinois, November 11, 1943.

the product yields and qualities were the same as when the plant was initially operated in 1940.

Benefited by the extensive background of Houdry commercial experience extending back to 1936, the new static bed plants are showing improved time efficiency records. Initial periods of experimentation and alteration have not been necessary, as illustrated by the performance of three recently started units. During the first fifty days operation, these three plants operated at on-stream time efficiencies of 96, 99, and 100 per cent. With these favorable starts, these units in all probability will exceed even the best previous operating records.

Catalyst requirements. Notwithstanding the gradual catalytic activity decline which is common to catalytic processes in the petroleum industry, products yields and quality are maintained remarkably constant throughout the catalyst life period. The flexibility of this process permits such a wide variety of conditions that practically all the catalytic activity can be utilized. In consequence, the catalyst consumption of Houdry fixed bed plants is remarkably small.

When the synthetic catalysts were first introduced, a minimum life period of about twelve months was conservatively anticipated, but commercial performance has exceeded expectations. The new synthetic catalysts have operated successfully for periods in excess of 15 months.

Based on a service life of fifteen months, a 10,000-bbl.-per-day Houdry plant consumes an average of 650 lb. of catalyst daily. Expressed in terms of throughput, this consumption averages one ounce of catalyst per barrel of charge.

Flexibility of the fixed bed process. In addition to reducing catalyst requirements, the inherent flexibility of the static bed process permits the conversion of a wide variety of charge stocks.

Heavy gas oils crack readily and unless conditions are carefully established there is an excessive loss of desirable products to gas and coke. Conversely, naphthas are refractory and require much more severe conditions to give the optimum results. In the various plants the operating conditions are selected for the several charging stocks by choice of proper catalyst activity, adjustment of pressure, and, to a lesser degree, temperature.

The most active commercial catalysts have more than twice the inherent activity of those of controlled low activity which are used for the heaviest gas oils. Oil partial pressures are varied from sub-atmospheric to 75 lb. per sq. in. gauge, and temperature is varied from 800 to 875°F. This wide flexibility in choice of conditions is of paramount importance in the cracking of both light and heavy stocks for the production of superior aviation fuels.

Research laboratory data. Earlier in this paper the research program instituted by Houdry Process Corporation to further the increased production of aviation gasoline was mentioned.

At this time we are not permitted to present significant data showing the advantages of the utilization of the combined cracking and treating processes for the production of aviation fuel. However, government regulations will permit disclosure of this information to persons who qualify under such regulations.

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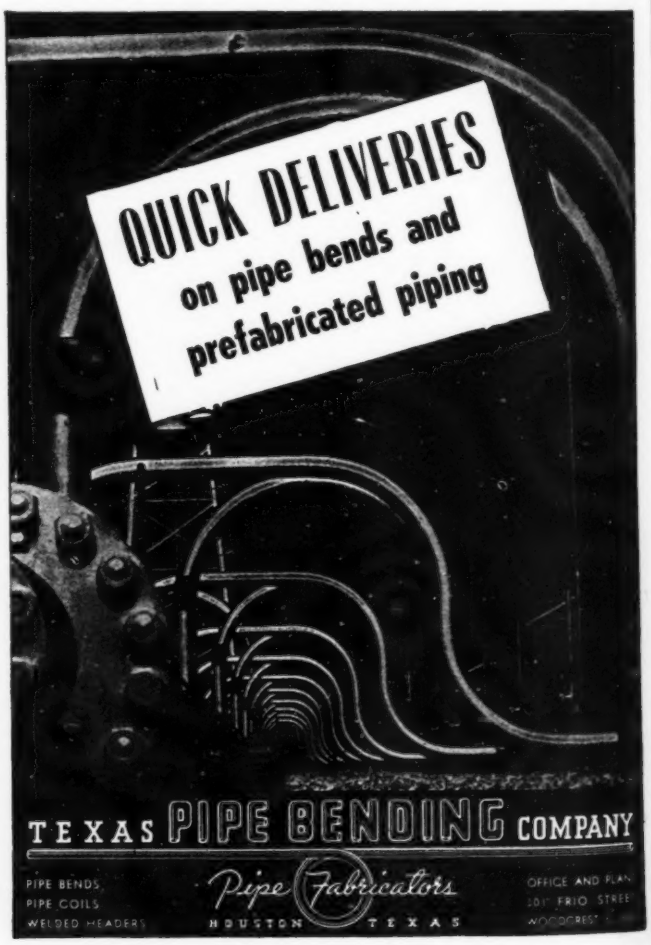


Economics of Combustion*

By EDWIN L. DENNIS, Chief Combustion Engineer
Coppus Engineering Corporation

THERE is no discounting the fact that American oil refiners have been and are being taxed to the limit of their resourcefulness and ingenuity in order to meet the skyrocketing demands for military gasoline, lubricating oils, and other products of petroleum. The extent to which they have met these demands in two short years is a story of its own and some day should be fully depicted by a competent narrator for the benefit of the American people and for the record of the industrial history of this country. Our only comment is that it has been a Herculean task well done and certainly an epochal achievement, which can and should be given a great deal of credit for the favorable turning point in the war and the speeding up of ultimate victory. We leave this task to others more able to do justice to the subject.

Because of the ability of the oil industry to meet the demands for more and more gasoline, rubber, TNT, and other products of petroleum for the war effort, the statisticians or "paper and pencil boys" have "gone to work" and have produced very alarming figures concerning the life expectancy of the industry. We have heard over the radio and read in the papers point blank statements that there would be no more oil in a very few years. This life line of the industry has been definitely predicted as running out in 8 years, 10 years, and only today we learned from a national news commentator that it would be 20 years. It is not intended to make light of, nor treat with levity, a very serious matter. The figures, of course, were arrived at by dividing the known oil reserves by the present rate of consumption. In this case, however, the dividend and divisor are both variables and therefore the quotient or life expectancy of the industry is certainly an unknown.

We do know that the producing part of the oil industry is not standing still but is keeping pace with the refiners and as a result more reserves will be discovered, more efficient recovery will be developed and other improvements made that will increase the "dividend" or oil reserves. We also know that even with the realization of every dream of peacetime prosperity and air borne passengers and freight traffic there will be a great decrease in the present demand on continental oil reserves when peace comes and even possibly before peace. We say possibly before peace because as victory approaches oil supply from sources now out of Allied hands will again become available. Therefore it can be said that a greatly reduced "divisor" or rate of oil consumption from continental supply is in the offing. With this thought of an increasing "dividend" and reducing "divisor" who can predict the "quotient" or ultimate life of the American oil industry?

We do not believe the industry is yet nor soon will be approaching the pitiful plight of an "old man in his dotage." Neither is the industry any longer as a "young man in his non-age." It has gone through the adolescence of youth when oil fields were wastefully exploited, refineries were run without thought of conservation of material and without too much thought given to efficiency. It now stands as a mature man, seasoned by trials and tribulations such as the present war and with the responsibility of a sizable and worthy "family represented by the synthetic rubber industry and the several younger brothers" of other associated industries. In this position we see the oil refiners literally on the threshold of life with a promising future, the ultimate success of which is assured by the lessons already learned.

We do not believe the scientists have developed or discovered all the uses of petroleum products or by-products. We believe a score or more now unknown products will appear within a very few years. Surely products from petroleum will find a prominent place in the "Age of Plastics" soon predicted. It is not fantastic to predict many other developments. The chemistry of petroleum is already a more fantastic realization than the wildest dreams of the early alchemists who sought to change lead into gold by use of the philospher's stone and other divers means!

And now to the more prosaic subject, "The Economics of Combustion as Applicable to Oil Refiners."

We hardly believe that anyone can accurately predict just how the return of peacetime operation will affect the end uses of various refinery gases and liquids.

We do believe, however, that decreasing supplies of fuel have forced refineries to change their former attitude toward "waste" products. Regardless of the ultimate or normal demand for synthetic rubber, the realization of the necessity of conservation of fuel, as well as of supplies of fuel, has forever changed the picture from that of 10 years ago. Heretofore refiners thought that waste products would always be available in excess of fuel requirements for the processes of modern refining. Up until now, very little technical thought has been devoted to the economics of combustion; too little attention to selection of burners and furnace design.

Heat requirements. Regardless of the advent of improved processes of catalytic cracking, thermal cracking and polymerization, hydrogenation or other complexes, the story of oil refining remains one in which an amount of heat is required per barrel of oil refined, the amount of heat (fuel) required varying according to the extent of the refining process and/or the methods of refining practices. This "heat" or fuel required is divided into the following uses:

A. For the heating of oil, liquid, or gases in the process of refining pertaining to the chemical and/or physical changes in the composition of the crude and intermediate products of refining by direct heat from products of combustion.

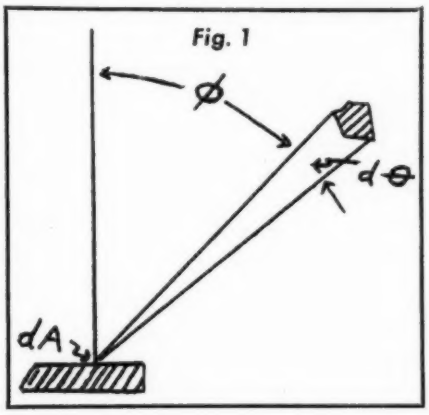
B. For the generation of process steam as differentiated from direct heat as in "A."

C. For the generation of steam for prime movers, pumps, and miscellaneous purposes.

Although the "fuel required per barrel refined" may not be the largest figure on that all important sheet, "total refinery costs per barrel run" of the cost accountant, we advance the thought that in too many instances this figure has been taken for granted while it actually offers a major opportunity for the technologist to affect major economics at relatively low expense to his company. We believe that in many instances the return on funds expended to increase thermal efficiency of existing equipment, and incidentally capacities in a number of cases, is more attractive than any other. It is possible that the spotlight is and has been played on the very major plant enlargements; and also, due to the fact that most men have been trying or doing the work of two, this opportunity has been neglected. Upon the return to normalcy more attention to "plain Jane" can be anticipated.

In too many instances in oil refineries

Fig. 1



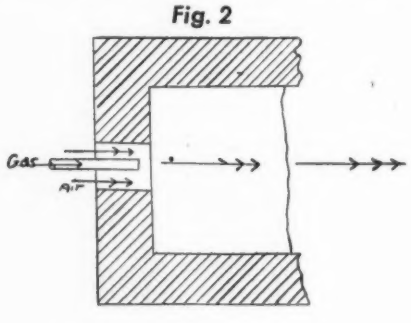
*Presented before Western Petroleum Refiners Association, Tulsa, Oklahoma, December 10, 1943.

the utilities department, i.e., steam and electric generation, have been treated as the proverbial step-child of the industry. Funds have not been made available for modernizing or improving existing equipment. Only when utilities are no longer able to supply the needs of production without consideration of good engineering practices and with complete disregard of efficiency are funds made available and then too often only with provisions for increased capacity without improvements of existing equipment. Unfortunately the power engineer is often made the goat by an unsympathetic operating department coupled with a Pontius Pilate attitude on the part of the technological department.

This is not, perhaps, a general indictment but within the past 12 months we have witnessed in three major oil refineries striking examples of this step-child attitude toward the utilities department or boiler house. In each case there had been an accumulation of butane in excess of storage facilities resulting in an emergency condition where it became necessary to return the liquid to the fuel system. In each case the fuel system was inadequately designed to handle any quantity of liquid in the gas mains. Also, each system was laid out so the first victim was the boiler house. That was not coincidence. Unfortunately in one refinery the dump was so great that the boiler house was not the sole sufferer. The liquid went past the boiler house washing pipe scale along the system and plugged completely every orifice in a large furnace fired with floor type burners. It required several days of unscheduled shutdown of this unit resulting in serious loss in throughput to drill out the ten thousand orifices in this one furnace only. The results in the two other refineries were not as serious but did cause a great deal of trouble and unnecessarily so. In each case the needless expense incurred would have more than paid for the complete cost of an adequate and properly designed fuel system that would have handled the situation as routine.

On the other hand, we know a fourth refinery that has not treated the utilities as a step-child. In this refinery the fuel system is designed so that the high B.t.u. refinery gases as well as butane are passed through a closed heater and brought to elevated temperatures to assure a dry gas main. The heat required is secured from backpressure or exhaust steam and is almost fully recovered in the gas. The cost of heating was negligible. As a result the mixed gases in this refinery's gas fuel system is always at an elevated temperature, approximately 130°F. average, and dry.

Fig. 2



The foregoing examples were used merely to illustrate that the first prerequisite of good economics of combustion is an adequate and properly engineered fuel distribution system in which is incorporated all the equipment necessary to cope with all the problems incidental to delivery of the fuel to the furnace site in good condition. This applies with equal importance to the liquid fuel system and the gaseous fuel system. The efficiency of fuel oil burners is probably even more sensitive to poor design than is the case with gas burners. No expense should be spared in assuring that oil under ample and steady pressure (relatively free from pulsation) and at proper temperature will be available at the furnace regardless of weather variables and/or change in fuel specifications. The steam for atomization should always be available at the furnace free of condensation and at constant pressure in the supply main. The original cost of a properly designed fuel system is not much more than that of an improperly designed system. The ultimate cost of an improperly designed system over a period of years may well be one-hundred-fold that of a properly designed system because its cost increases with each day of less efficient operation.

It is said, "A woman's work is never done." This applies equally well to plant engineers. Constant changes and additions, which come by degrees, may necessitate emergency fuel lines or disturb the general system so that a previously well designed system might well become inadequate. It is not a reflection on plant engineers that such cases might be unnoticed due to circumstances and also the fact that the effect of additions and changes is cumulative.

The fuel distribution system of any refinery deserve an annual or semi-annual survey carefully made and a detailed report of recommended improvements. This report deserves prompt attention and action on the part of plant management.

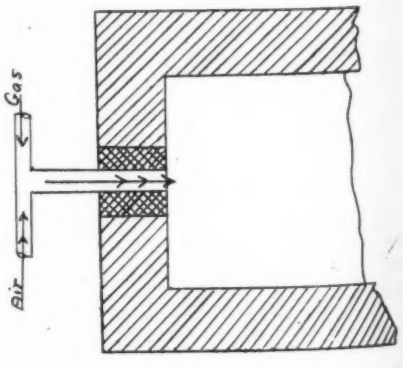
In oil refineries there are generally fuels that have no commercial value. These are truly waste fuels unless used by the refinery. We speak of tank bottoms, acid sludges, or any non-saleable material containing combustible matter. This paper does not treat on these fuels but it should be stated that the correct end use of these should be in the boiler house, as is the general practice. The facilities for handling deserve just as much consideration as any other refinery facility.

Stack losses. A study of the economics of combustion of a refinery would be most incomplete if some attention were not paid to the greatest loss of generated heat. We refer, of course, to "stack losses," or to that energy dissipated to the atmosphere in the products of combustion leaving the many stacks in every refinery. The "yard stick of economy" needs be applied in any industry whenever changing conditions might result in a different measure. We believe conservation of fuel within the oil industry is as important as it is at a central station power plant. This has been made more apparent within the past 3 years than ever before but in the language of "Dog Patch" and "Lil' Abner" a barrel of fuel saved at the refinery has just as much fuel value as one sold outside the industry "as any fool can plainly see."

With this homely observation it might be concluded that any investment in waste heat recovery equipment that would be economically sound for a central station would be so for an oil refinery. That, however, is not always true from a dollar and cents angle. The dollar value of a barrel of fuel, or its equivalent, at the refinery is less than its value outside the industry. The outside user must add transportation and handling costs.

On the other hand, stack temperatures on many refinery furnaces are higher than those encountered by most other users of fuel. On many cracking units stack temperatures approach 1000°F. In such cases we believe an engineering analysis will demonstrate that the addition of recuperative equipment would be a sound investment. Air preheaters and auxiliary equipment require little maintenance and are trouble free in operation. It is hardly possible to fix a point where addition of waste salvage equipment would be universally applicable in oil refineries as a sound investment. In this respect the thought is advanced that a point of beginning might be taken as any heater having a

Fig. 3



heat input of 50,000,000 B.t.u. per hr. and a stack temperature of 700°F. or above would be deserving of a careful study to determine the "pay off" of recuperative equipment. With this starting point the various furnaces in a refinery could be classified immediately into those on which recuperative equipment would be a sound investment and otherwise.

There is an opporunity for the manufacturers of waste heat recovery equipment to cooperate with the oil refiners in a complete investigation of the possibilities of affecting material fuel savings by the judicious application of recuperators on refinery heaters as well as boilers. It is to be hoped that postwar industry will be frugal and conservative but that funds will be made available for those needs to *conserve*, be it fuel or any other resource of our nation.

Burner selection and furnace design. So far, we have dealt with the economics of combustion only to get the fuel to the furnace and to salvage, when practical, heat from the stack gases. There remains the economics of burner selection and furnace design to be given attention.

In the first place attention should be called to the error in nomenclature as refers to the word "burner." Webster defines the word thusly: "burner—noun, 1. That which burns. 2. The part of a gas fixture, furnace, etc., where the flame is produced." A burner as commonly accepted certainly does not conform to the definition because flame is not produced in the burner. Actually, a gas burner is a mixing device designed to mix the combustible with the necessary air to carry out combustion. The degree of perfection reached by the burner in mixing and proportioning the fuel and air to meet the needs of the application should determine burner selection.

This discussion will treat burners as mixers and proportioners of fuel and air and tell how their design affects the economics of combustion in oil refineries.

Bunsen stated, "An ideal gas burner is one with an infinite number of gas orifices interposed across the air stream." In his next statement he said, "This cannot be approached in practice because the space occupied by the gas conduits would soon occupy all available space." What Bunsen meant was an ideal gas burner would be one that would deliver a completely homogeneous mixture of correctly proportioned air and gas to a furnace. To what extent modern design has been able to approach Bunsen's ideal burner will be discussed subsequently.

It must be noted that on some applications the ideal burner described by Bunsen would not be desirable. Some

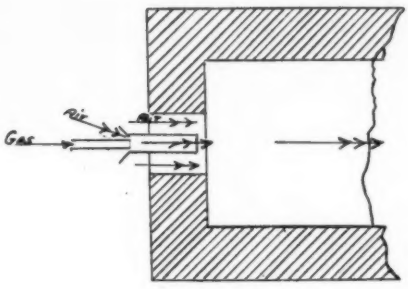


Fig. 4

furnaces or processes are so designed that slow or progressive combustion is paramount. In the oil industry, however, such applications are the exception rather than the rule.

Dr. W. Trinks, professor of mechanical engineering, Carnegie Institute of Technology, in his book "Industrial Furnaces," summed up the problem of proper burner selection in one simple sentence, "Burner design, therefore, is mixed design."

There is no gas burner that can produce one single B.t.u. more than any other burner in burning a fixed quantity of the same gas to the end products of carbon dioxide and water vapor. There can be, however, a vast difference in the B.t.u.'s that will be recovered or are recoverable from the products of combustion of a fixed quantity of the same gas on same furnace when fired with different burners.

It is necessary to review some of the chemistry and physics of combustion as well as the mechanisms of heat transfer to show the importance of this statement.

It is generally accepted that combustion is a series of chemical reactions of progressive oxidation of a combustible material. These reactions liberate heat in amounts proportionate to the degree of oxidation carried out, the chemical analysis of the fuel, and rate of fuel consumption. If sufficient oxygen is supplied to complete the reactions, the same amount of heat will be liberated in combustions of a fixed quantity of fuel regardless of the rate of combustion or the intermediate reactions that may or may not exist during the process of complete combustion.

The laws of conservation of energy and mass cannot be avoided. "Energy cannot be created or destroyed." "Matter cannot be created or destroyed."

The rate at which combustion takes place in a furnace is affected by many factors. In practice those that are most important are the intimacy or degree of complete mixture of the fuel and air upon entering the combustion space and the temperature not only of the combustion space but also of the flame propagated. When a homogeneous mixture of gas and air is ignited that contains exactly the correct amount of oxygen for complete combustion the rate of ignition is maximum. The rate of ignition is retarded almost equally by a deficiency or an excess of oxygen carried in the air. The ultimate temperature of the products of combustion (flame) is likewise depressed by either excess air or deficiency in air.

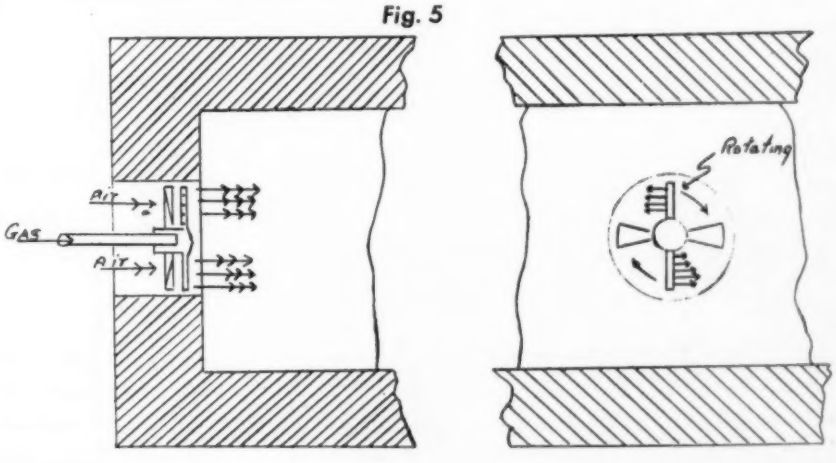
It is common in practice always to supply excess air through burners to be certain that oxidation or combustion will be complete and all energy or B.t.u. released in the furnace. The amount of excess air required by a burner to assure this is a direct measure of the degree of mixing provided by the burner. Especially does this become important when high unit heat releases are desired.

The important gas law pertaining to burner and furnace relationship is of course: "The volume a gas assumes is in direct proportion to the absolute temperature and inversely proportionate to the absolute pressure." As absolute furnace pressures encountered in industry are so nearly constant the effect of pressure on volume may be disregarded.

Therefore, when the reaction of combustion of a gas is speeded up, the temperature of the combustion gases will rise as all of the heat is liberated nearer the burner and the combustion gases will expand closer to the burner tend-

(Continued on Page 210)

Fig. 5



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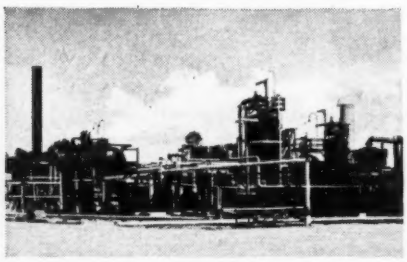
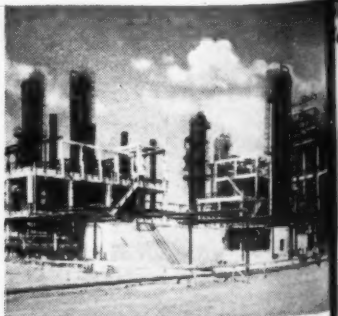
1 WITH EVERY MODERN REFINING PROCESS at their finger tips . . . Kellogg process e gineers so conceived the combination and arrangement of uni for the vast project that the refinery—as designed—is producin aviation gasoline with *two-and-a-half times* the efficie cy of the industry at larg Simultaneously the secon major requirement of th project is being more tha realized—for the butylene produced will add over on hundred million pounds rubber annually—10% of t nation's supply!



Propane treating unit—simultaneously removes asphalt and salt from reduced crude.

2 THE EFFICIENCY of the full-scale refinery is its own measure of the accuracy of data yielded by Kellogg laboratory and pilot plants. The yield from each interrelated processing step was pre-determined with such uncanny accuracy that all commercial units function with optimum results both individually and *collectively*.

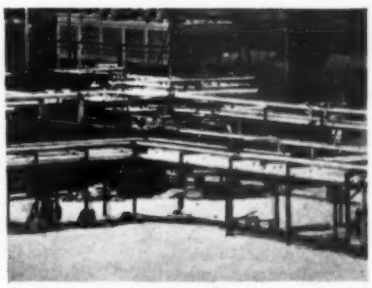


Gas recovery system was designed fr mass spectrometer studies.

3 **EXCLUSIVE CHEMICAL ENGINEERING DATA** continuously compiled over the years by The M. W. Kellogg Company proved its full value in the successful development of Cities' project. Based on this data and Kellogg's development of *Fluid* catalytic-cracking . . . the "Cat-Crackers" in this refinery were designed *before* a single such Fluid unit was in operation!

...ttery of 3 Fluid "Cats" makes ex-...emely high production possible.

4 **COMPRESSED** into a six months' period . . . this engineering job for Cities is the only one of its size ever undertaken in the history of refining. Over 500,000 man-hours of mechanical engineering were put into the project by the Kellogg staff. The blue-prints alone can be measured by the acre. And the responsibility to Cities for delivering a refinery producing to "specs" was Kellogg's alone.

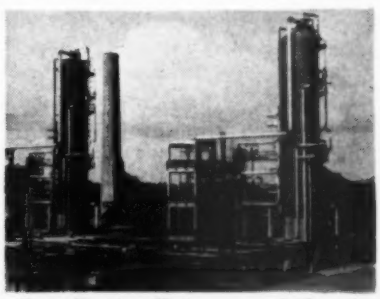


Intricate piping specifications were accurately established by exclusive stress measuring device.

5 **CONSTRUCTION-WISE,** more refining records were set. Better than 25,000,000 man-hours ...ere expended and at peak of the work, M. W. Kellogg's ...rmanent construction crew supervised 11,000 workmen ... the job. Working ...inst time and the infi...te complications brought ...out by the war . . . the ...ew built and linked ...irteen different major ...fining units — requiring ...0 miles of continuous ...elding; 1,100 miles of ...pe and tubing; a power ...ant big enough to supply ... city of 250,000 people ...th electricity!

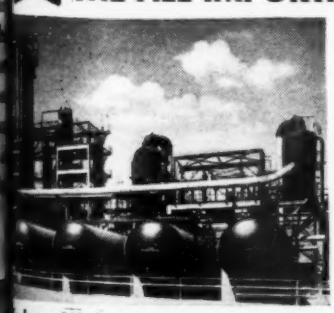
Power house, railroad spurs, docking facilities are but a few of the supplementary projects completed.

6 **ANOTHER REASON** why Kellogg-completed plants operate as designed can be found in the work done by the Kellogg initial operations staff on the Cities' project. These men, with broad experience in all phases of modern refining, assisted the refinery's permanent staff to start up each unit as it was completed. And each unit operates successfully *—as specified.*



Twin Topping Units—two of 13 major units to be put on stream.

7 **THE ALL-IMPORTANT PROTECTION** of the client's interests in the process rights is always part and parcel of M. W. Kellogg operations. Licenses for all major refining processes embodied in the Lake Charles refinery were arranged by Kellogg.



...dern Alkylation units utilize both butenes and pentenes.

THE M. W. KELLOGG COMPANY

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(Continued from Page 207)

ing by expansion to spread over the furnace nearer to the front or burner wall, but this heat distribution can be governed. With increased combustion speeds, it will be seen that much higher heat releases can be secured in a furnace than is possible where secondary combustion takes place.

Heat transmission. From this point we must go into the mechanisms of heat transmissions.

We can consider that by propagation of combustion from gases, a mass of heated gas is liberated into the furnace containing a certain amount of heat and having a temperature proportionate to the rate of combustion and somewhat inversely proportionate to the mass occupied. The temperature of combustion will be higher with less excess air, provided combustion is complete to the end products because of less mass and higher again if combustion is completed in less volume of the furnace.

Transmission of heat is accomplished by only three mechanisms—conduction, convection, and radiation. When transmission of heat takes place all three of the mechanisms are employed to some degree and the quantities transferred in furnace designs can be controlled to some degree into each of the three mechanisms. Furnace design, location and distribution of the heat absorbing surfaces of a furnace, are prime factors in governing the heat transmission efficiency of a furnace.

In speaking of the efficiency of a furnace we refer to the amount of heat absorbed by the surfaces, such as tubes, and transmitting this to other fluids, etc., separated from the combustion gases of the furnace by the retaining walls, in proportion to the amount of heat liberated by the combustion in the furnace. The mechanism of absorption of heat through the material of the retaining wall of the fluid will naturally be more by conduction than either by convection or radiation.

In turn, the temperature of the retaining walls, or amount of transmission of heat to the walls, will be more by radiation and convection than by conduction.

The definitions of the three mechanisms of heat transmission are:

Conduction: Transfer of heat from one part of a body to another part of the same body, or from one body to another in physical contact with it, without appreciable displacement of the particles of the body.

Convection: Transfer of heat from one point within a fluid, gas, or liquid, by mixing of one portion of the fluid with another of different temperature. In natural convection, that is, without forced mixing from external source, the motion of the fluid is entirely the result of density resulting from temperature differences within the fluid mass.

Radiation: Transfer of heat from one body to another, not in contact with it, by means of wave motion, of heat rays, through space.

The physical laws governing transmission of heat by three mechanisms are available in any mechanical or chemical engineer's handbook. We use these in the following development of the furnace mechanism without specific quantitative analyses.

When a furnace is operating normally, a condition of stability of heat transmission from the heat liberated in the combustion products to the heat absorbed by the surfaces supplied for that purpose will be essentially established. Conduction, convection, and radiation factors will be established in relatively the same proportions of the total amount of heat transferred.

McAdams, in "Heat Transmission," states in the chapter on radiant heat, "Of the gases encountered in heat-transfer equipment, carbon monoxide, sulphur dioxide, ammonia, and hydrogen are the only ones with emission bands of sufficient magnitude to merit consideration."

In the combustion of the saturated hydrocarbons, McAdams further states, "The constituents, carbon dioxide and water vapor, account for the major portion of the radiation of gases in furnace chambers, and no large error is introduced by neglecting the others."

"The amount of heat radiated by any particle is proportionate to the fourth power of the absolute temperature." (This is established in the "Stefan-Blotzmann Law"—$a = 0.172\ p\ A\ (T/100)$ where A = radiating area, p = the emissivity factor of the surface, and T = absolute temperature in °F.

Gases containing carbon dioxide and water vapor when heated to high temperatures emit invisible infrared rays of radiation. (Mark's Handbook, Third Edition, page 409): *"Under conditions of high temperature and thick gas layer or high concentration of the radiating constituents, water vapor and carbon dioxide, this mechanism (radiation) of heat transfer from gases to surfaces outweighs that of convection in importance."* (See *Industrial and Engineering Chemistry*, Vol. 19, p. 888, for calculations of this type.)

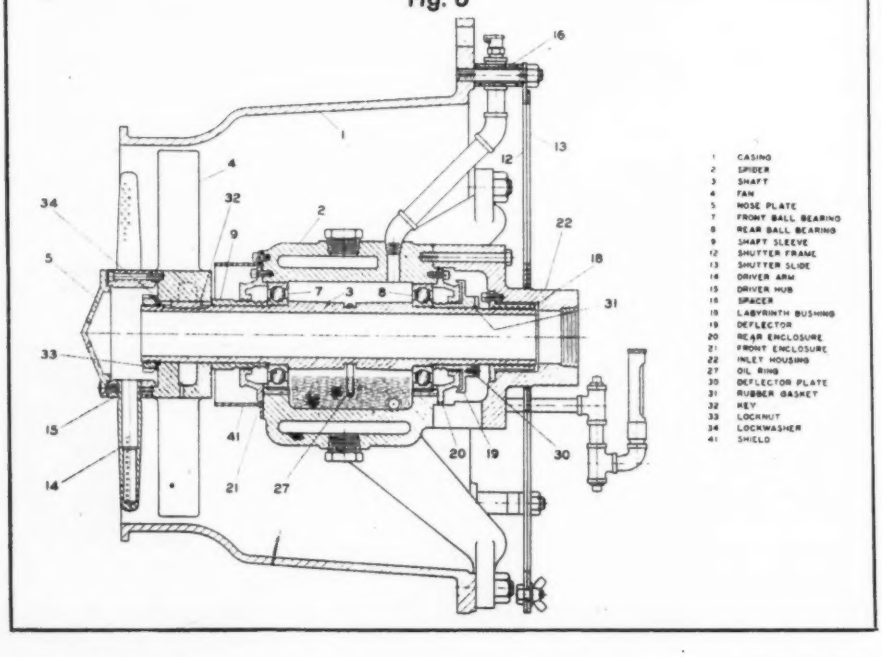
In radiant heat transfer from one solid to another, several laws come into effect; one being the emissive power of the surfaces, which is established for most materials, and is equal to the total radiant energy radiated in all directions from the surface of one side per unit of time per unit of area of B.t.u. per hour per square foot.

The intensity of radiation from a surface, designated by, "i" in Fig. 1 is the radiant energy emitted per unit of time of solid angle with the apex at the radiating area, per unit of projected radiating area, the projection being onto a plane normal to the radiating beam. Let "d A" (Fig. 1.) equal a small surface element of a radiating body. Within the solid angle, $d\Theta$, making an angle ϕ with the normal "dA," let the quantity of energy being emitted from "dA" per unit time equal "dq." Then intensity, "i," of radiation of the surface "dA" in the direction of ϕ is defined by the equation:

$$dq = i\ dA\ d\Theta \cos \phi$$

The normal intensity of radiation is that value for "i" when the angle ϕ is zero.

Fig. 6



The absorptivity of radiant energy of a surface is that fraction of radiant energy, incident on the surface that is absorbed.

The reflectivity of a surface is that fraction of radiant energy incident on it that is transmitted through it by radiation.

It will be seen that since energy cannot be created nor lost, that the sum of the absorptivity, reflectivity, and transmissivity will equal unity. However, for thick opaque bodies or solids the transmissivity equals zero and then the sum of absorptivity and reflectivity will equal unity.

It would require volumes to completely present the picture of heat transfer but the foregoing presentation is sufficient to draw some positive conclusions regarding the economics of burner selection.

Summarizing generally in regard to refinery practice we find:

Use of air in excess of that required for complete combustion within a furnace will decrease the amount of heat absorbed by the heat absorbing surfaces without exception. (Stack losses are increased by use of excess air).

In a furnace employing radiant heat tubes and convection tubes, (as commonly understood), the amount of heat absorbed by the radiant tubes will vary directly as the fourth power of the absolute temperature of the mass emanating the radiant energy and inversely as the distance separated from the source of radiant energy.

As a specific example, assume that the products of combustion produced by one burner are at a temperature of 2200°F. and those of another on an identical furnace are at 2600°F. The amount of radiant heat emanated by the products of combustion of the second burner will be $\frac{2600^4}{2200^4} = 1.95$ or 95 per cent more than the radiant heat emanated by the first. Likewise the amount of heat absorbed by tubes in radiation would be correspondingly greater for the same rate of fuel consumption in each case.

As the total amount of heat generated by each burner is identical, then the products of combustion from the first burner will contain materially more heat upon entering the convection section and will be at a larger volume. As a result the convection tubes will absorb more heat than would be the case with the second burner, but in no case can this increase in convection absorption equal the amount lost in radiation. The total heat absorbed from the products of combustion of the burner producing the highest flame temperature will always exceed that absorbed from the products of combustion of the burner producing a lower temperature.

Because a burner produces products of combustion at a higher temperature than another it does not follow that wall or tube surface temperatures will be higher, nor that the amount of heat absorbed per unit area of tube surface will be increased over the maximum unit area absorption in the case of the lower temperature flame.

A burner that produces a lower temperature flame does so for one or both of the following reasons: (a) Poor mixing of air and gas at the burner resulting in air and gas strata entering the furnace and consequent delayed complete combustion, or (b) excess air is employed.

In the usual refinery furnace a burner should eliminate from the furnace the necessity of serving both as a mixing chamber as well as combustion space.

Heat cannot be absorbed until it has been generated. Therefore, if a burner does not deliver a complete mixture of air and gas but instead delivers air and gas strata into a furnace the chemical reaction of combustion will not have been completed nor the total heat generated until the mixing is completed by furnace currents rather than by the burner. This results in "late" generation of total heat and will result in high temperatures at some depth in front of the burner, flame impingement or local "hot spots."

As CO_2 and H_2O vapor are the important gases that give up radiant energy, then if these end products of combustion are produced "deep" in a furnace they will not give up radiant energy to tubes in the front part of the furnace to the same degree as would a burner producing CO_2 and H_2O nearer the burner. Neither would these essential gases remain within the furnace as long when produced farther away from the burner and therefore the time element would be decreased resulting in reduced absorption of radiant heat.

On the other hand, a burner that delivers a homogeneous mixture of air and gas of the proper proportion to a furnace, eliminating from the furnace the necessity of serving as a mixing space, will produce complete combustion to the end products CO_2 and H_2O in the minimum time and at the maximum temperature and at the minimum distance from the burner. (Note: Provided the entering velocity of the mixture is not such as to produce blow torch action). As soon as produced, the CO_2 and H_2O molecules emanate radiant energy of the furnace and reduce absorption to the rear of the furnace as compared to conditions previously outlined. This results in more uniform absorption throughout the radiant section of the furnace.

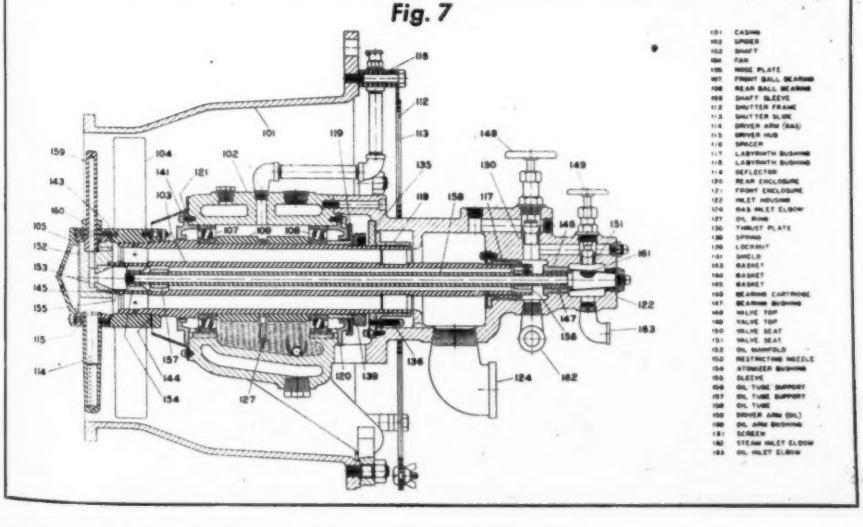
The importance of these phenomena can be illustrated by many case histories. In one refinery a simple conversion job increased boiler capacity from a maximum of 90,000 lb. per hr. to 130,000 lb. per hr. was secured from two boilers with a reduced stack temperature. In another plant a boiler designed for a maximum output of 50,000 lb. per hr. has been operating for four years at 75,000 lb. per hr. In yet another a boiler rated at 175,000 lb. per hr. is now operating at 235,000 lb. per hr. without any difficulty. In a like manner, many oil heaters have secured increased throughputs by the same proportions and at reduced or no higher stack temperatures. There is no intention to set the above up as general conditions but many more just as bad still exist.

No burner can produce an extra B.t.u.; however, in many instances it is possible that one burner can salvage millions of B.t.u.'s over another.

In this respect it is well to note that an improperly engineered installation of a good burner may be as bad an offender as an improperly engineered burner installed in the best possible manner.

Burners. Gas burners may be classi-

Fig. 7



fied in four groups as follows:

A. Gas and air are mixed in the furnace, i.e., during combustion. (Fig. 2.)

B. Gas and air are mixed outside the furnace, i.e. before combustion begins. (Fig. 3.)

C. Gas and air are partially premixed outside the furnace with the rest of air added in the furnace. (Fig. 4.)

D. Gas and air are mechanically mixed at the point of entrance to the furnace by utilization of the gas pressure to perform work in propelling movable orifices through a plane of rotation across the air stream and to drive a propeller fan to deliver the proper amount of air to the mixing plane of rotation. (Fig. 5.)

In all figures:

→ indicates raw gas.

→ indicates air.

→ indicates partial mixture of gas and air.

→ indicates complete mixture of gas and air.

It is not necessary to comment on the rapidity and completeness of mixing secured from the four basic designs illustrated.

Oil burners are generally put into one of two classifications.

A. Mechanical atomizing burners.

B. Steam atomizing burners.

No discussion of the merits of one over the other will be presented, but in general we believe that oil burners using steam for atomization are more suitable for general application in oil refineries. Their advantages outweighing their disadvantages as compared to mechanical atomizing oil burners.

Combination, or so-called combination gas and oil burners may be classed in two general classifications:

A. Those burners where two separate burners are combined to use the same furnace opening but both burners operate as separate units.

B. Those burners where the gas burner and oil burner are integral parts of the same mechanism thus securing the same degree of mixing with one fuel as with the other and producing the same heat pattern on either fuel or on both fuels simultaneously fired.

Combination burners in class B have only recently been put on the market, (in limited numbers temporarily), after three years of proving on oil heaters in a southern and Mid-Continent oil refinery.

In 1939, before the Wichita, Kansas, meeting of the Western Petroleum Refiners Association, a paper entitled "New Developments in Burners and Their Applications" was presented and later published in the October, 1939, issue of *Refiner and Natural Gasoline Manufacturer*.

This paper dwelled at some length on the performance of gas burners in classification D, Fig. 5, which at that time was entirely new to Mid-Continent refiners. At the present time, there are over 1,000 installations of this type burner in various oil refineries, many of which are in the Mid-Continent.

Fig. 6 is used in this article to show the mechanical design of this type gas burner in order to correlate the description of combination gas and oil burners, falling in class B, combination burners, which are yet new in the industry.

Fig. 7 shows the mechanical details of the new combination burner.

In the conventional oil burner atomizer oil spray is ejected under pressure from the burner tip, which is centrally mounted in the burner casing through which the air for combustion is drawn by furnace draft or through which air is forced by forced draft. The spray of atomized oil is generally conical in shape but in some instances a flat shaped spray is used. Curved vanes are generally placed at the entrance to the burner casing to impart a swirling motion to the air entering the furnace in order to speed up mixing of air with the burning oil spray in the furnace with resultant shorter flame from the burner.

The conventional oil burner therefore can be compared directly to a gas burner of type A, Fig. 2, *where the fuel and air are mixed in the furnace—during combustion.*

In most oil refinery applications a gas burner of type A, Fig. 2, would be completely undesirable due to the delayed combustion secured resulting in a long flame and less efficient operation than would be secured from any other of the four general classes of gas burners illustrated.

In a like manner the conventional oil burner is objectionable as it does not remove from the furnace the necessity of serving both as mixing space as well as combustion space.

The heat pattern of a furnace fired with the conventional oil burner is entirely different from that produced in the same furnace by one of the better gas burners.

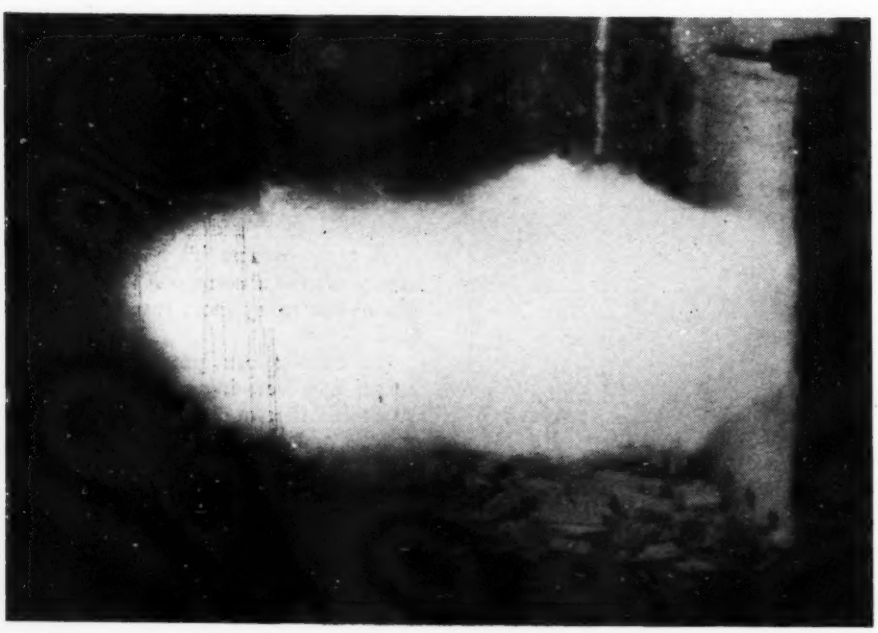
In combination firing of oil heaters extreme care is often necessary in changing from one fuel to the other in order to prevent material changes in charge temperatures as well as to prevent header leaks from developing.

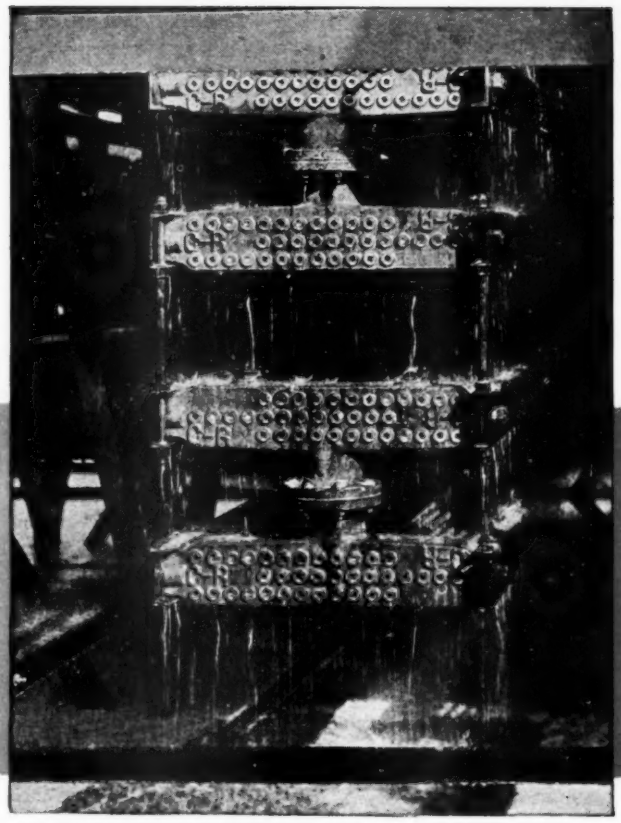
Unlike gas, oil produces a luminous flame no matter how finely the oil spray may be pulverized or atomized unless it is burned with excess air of such great quantity that the heat loss to stack gases would be prohibitive. A flameless or blue flame oil burner may be all right for a cook stove but entirely unsuited for refinery furnaces.

The chemistry of combustion of fuel oil is not unlike that of gas. Both hydrocarbons and the end products of combustion are CO_2 and H_2O. The oxidation reactions in burning oil are simply more complicated.

The gas burner of class D, Fig. 5, was developed on the logic that Bunsen's ideal burner could be simulated by using orifices of relatively limited numbers moving rapidly across the entire air stream and discharging the gas transverse the air stream. The same logic was

Photograph of class "B" combination oil and gas burner (Fig. 7), operating on oil at rating of 21,000,000 B.t.u. per hr., mounted in box type furnace with center line 24 in. above furnace floor. Burner is 15 in. diam. (Note rubble on floor to increase floor radiation to side walls)





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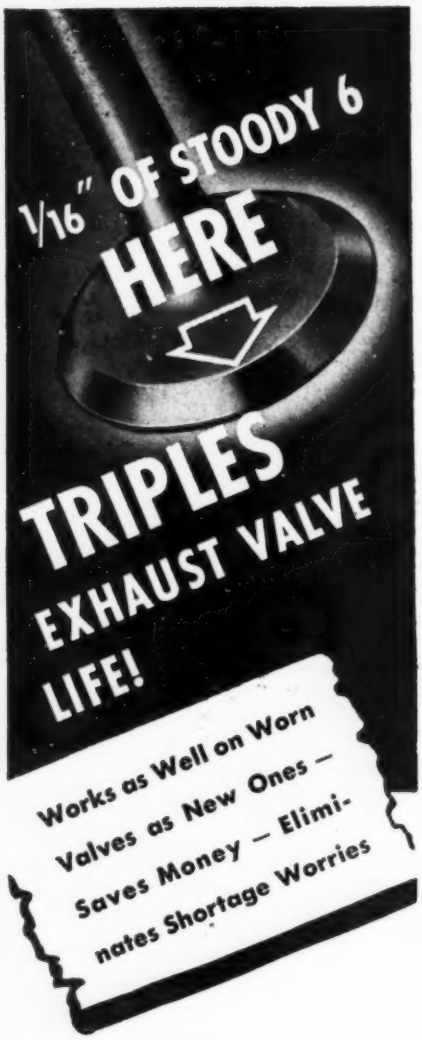
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used in designing and developing the oil burner part of the combination burner of class B, Fig. 7.

Referring to Fig. 8, it will be noted that a conventional type steam atomizing oil gun is built into the center of a gas burner of class 4, Figs. 5 and 6. Instead of the atomized oil going into the conventional center tip after atomization, it will be noted that it goes into oil driving arms, part No. 159, Fig. 7, and from these arms is discharged through orifices (not shown on drawing as half of arm is shown cut away), drilled at different radii from the center of rotation and essentially transverse the air flow through the casing. The reaction of the atomized oil jets from the orifices furnishing the necessary energy to drive the fan at proper speed to deliver the correct amount of air to the furnace.

By comparison it will be noted that the gas burner part of Fig. 7, remains the same as a class D gas burner shown in Fig. 6.

It will be further noticed that essentially the same degree of mixing of either gas or oil will be secured across the entire air stream and before entrance into the furnace.

A combination burner (or straight oil burner) of this design, having a throat diameter of 15 in., operating at a heat release of 20,000,000 B.t.u. per hr. from oil, will have a flame length of 3 ft. and less than 10 per cent excess air in the products of combustion.

In furnace design the question has often been raised: Should the furnace be designed for the burners to be used, or should the burners be designed to the furnace?

We believe that the burners should be designed to the furnace and to the process. The burner manufacturer should be given as much detailed information as possible on the application and service and not merely asked to bid on burners to deliver so many B.t.u.'s per hr. from fuel of certain specifications and at some pressure.

Whenever burners are moved from one service to another or in the event fuel specifications have changed since installation, the burner manufacturer should be contacted advising what the changed duty will be and at the same time giving the burner number. A manufacturer who maintains proper engineering records at the factory can then advise if any changes should be made in the orifice drilling to secure maximum efficiency under the new conditions. Orifice drilling changes should be engineered whenever possible and not made by hit or miss methods.

Burners should never be purchased on first cost figures. A burner that is 1 per cent less efficient for a specific job than another will eventually cost many times more than the more efficient burner, even if it were delivered to the user free of charge.

Summary. We have covered proper design of fuel systems, maintenance of same, possibilities of economies by use of waste heat recuperative equipment, and proper selection of burner equipment. If every oil refinery will carefully study all furnaces now in operation and carry out the improvements that will conserve fuel in only those instances where the savings will pay a handsome return on the investment, they will have effected the greatest fuel saving of all time. At the same time a most splendid example will be set for other industries.

This paper has not dwelt on the importance of maintaining clean tube surfaces in boilers, heaters, and other heat transfer equipment nor the economies often available by use of superpositive steam-electric stations in oil refineries of relatively large capacity. This does not detract from their importance. A separate paper could be written on those subjects.

It should be stated, however, that a superposition steam-electric power plant will pay for itself in 6 years in any refinery that burns an equivalent of 1000 bbl. of oil per day in the boiler plant and will effect approximately a 15 per cent reduction in fuel consumption for steam generation. With respect to superposition steam generation, it might be noted that in some instances superposition offers as attractive an investment for smaller oil refiners as for large. For instance, a refinery having a total demand for steam in the amount of only 100,000 lb. per hr., at a pressure of 150 lb. per sq. in. and an electric demand of approximately 1000 kw-hr. or more offers good possibilities in this direction.

Under such conditions a steam generator of 45,000 to 50,000 lb. per hr. at 475-lb. pressure and 560° T.T. of steam together with a 1000-kw. back pressure turbo-generator (topping unit) with exhaust pressure at 150 lb. might prove to be a very profitable investment to a refiner. It is suggested that superposition has not been given proper thought in relatively small plants and that this high-hat attitude has been a mistake.

The economics of combustion resolves simply to conservation of fuel, and this important matter certainly deserves careful study in the oil refining industry.

The burner manufacturers are responsible to the oil industry to continue to improve combustion equipment and deserve the full cooperation of the oil industry in working in that direction. —— ☆ ☆ ☆ ——

Practical Design of Foundations for Vertical and Horizontal Vessels in Refineries*

By J. A. SHJARBACK, Refinery Division
The Fluor Corporation, Ltd.

THERE are many problems that should be settled before the design engineer can proceed with a design problem. It is erroneous to give to the design engineer information on soil bearing value without a thorough investigation. Atmospheric and climatic conditions must be taken into account, as well as wind pressure and seismic forces. Accurate information concerning strength of concrete, building code to be used, and specifications by the owner should be provided. A preliminary layout showing location of all equipment is essential. Information concerning height of equipment and type of material to be used in frames and buildings must also be available.

Soil bearing. Soil investigation should be placed in the hands of a competent soil mechanic engineer. From his information, it is possible to arrive at a safe soil pressure for any depth. His information tells for any size footing the amount of soil pressure to use to get the same amount of deflection throughout the site.

Example

Load settlement relations for spread footings

Minimum width, ft.	Safe load, tons per sq. ft.	Settlement for safe load, in.	Safe load for 0.5-in. settlement, tons per sq. ft.
2	4.5	0.47	4.5
3	5.0	0.57	4.4
5	6.5	0.83	4.0*
7	8.0	1.17	3.5
10	10.0	1.74	2.5
25	26.0	8.34	1.0

*Soil pressure to be used.

Using variable soil pressures for different size footings, therefore, is not practical. It is common engineering practice to use the soil pressure for the average size footing on the site given in column 4.

Generally, by taking a certain number of borings at random throughout the site, it is possible to find out whether the strata are parallel or sloping. It is possible that the first layer of strata would take only a very light safe load, while the second layer of strata would take a much heavier safe load. This would give the design engineer some indication of the depth of footing. All this information should be given to the design engineer in order to prevent costly mistakes based on wrong assumptions.

Atmospheric and climatic conditions. It would be well to know the atmospheric and climatic condition at the site where the refinery is to be constructed. It is not necessary to consider tornadoes, hurricanes, or wind storms. The weather bureau of the U. S. Department of Agriculture has over 100 stations throughout the United States with a possible record of over 50 years at each station. From any locality it is possible to get the maximum wind pressure in pounds per square foot. It is well to know before hand whether to use the full wind pressure on the projected area or to make a reduction due to curved surfaces. Wind load on all piping, platforms, and all other projections from the vessel must be considered. Seismic force should be definitely stated. Most commonly used factors are 0.1G and 0.2G.

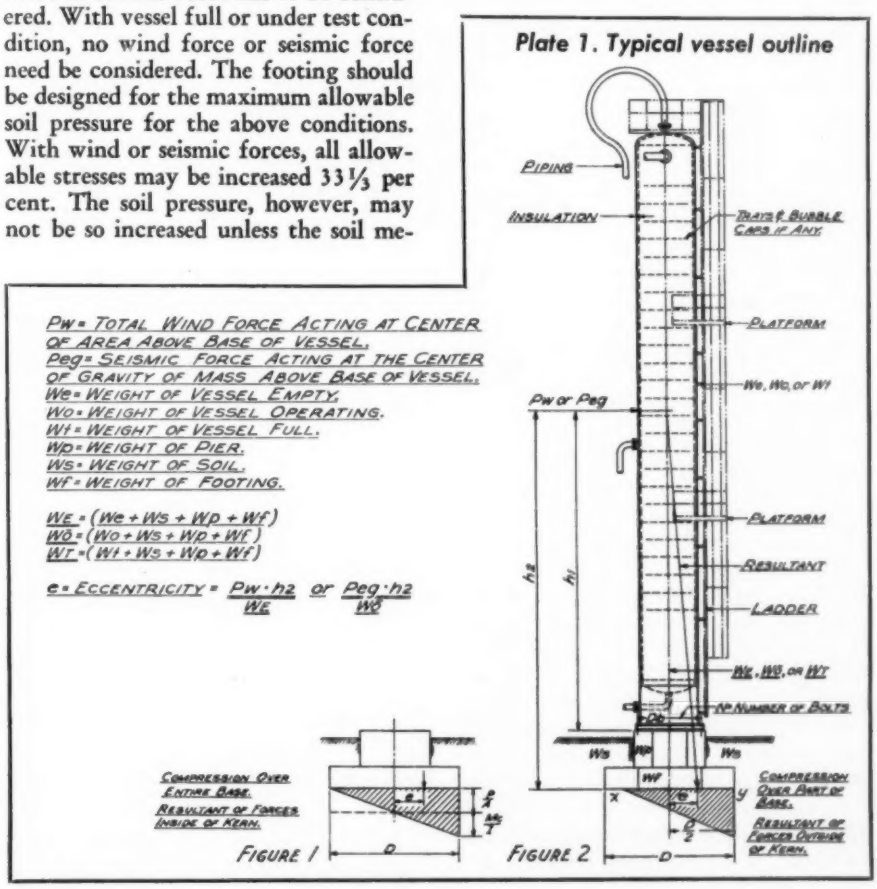
The scope of this paper will be limited almost entirely to the discussion of designing foundations for vertical and horizontal vessels.

Self-supporting vertical vessels —simple footings. Vertical vessels are subject to three conditions. They may be empty, operating, or full. With vessel empty, or operating, either wind force or seismic force has to be considered. With vessel full or under test condition, no wind force or seismic force need be considered. The footing should be designed for the maximum allowable soil pressure for the above conditions. With wind or seismic forces, all allowable stresses may be increased 33⅓ per cent. The soil pressure, however, may not be so increased unless the soil mechanic engineer has so stipulated. Under full or test conditions there should be no such increase. To get the maximum allowable soil pressure for wind or seismic force, and still not have compression under the entire footing, the stability ratio must be satisfied, otherwise the soil pressure has to be reduced by increasing the size of the footing.

Combined footings. To support two or more vessels the footing should be designed for various combinations of loading with no wind force or seismic force and with some vessels empty and others full or under test condition. When considering wind force or seismic force all vessels should be empty or operating. The center of gravity of the vertical loads and the center of gravity of the footing should coincide for operating conditions, giving a uniform soil pressure throughout. The stability ratio must be satisfied for a combined footing the same as for a simple footing. Otherwise the maximum soil pressure will govern.

Footing for elevated vessel. Sometimes vertical vessels are elevated for some process reason. In this case either

Plate 1. Typical vessel outline


Pw = Total Wind Force Acting at Center of Area Above Base of Vessel.
Peg = Seismic Force Acting at the Center of Gravity of Mass Above Base of Vessel.
We = Weight of Vessel Empty.
Wo = Weight of Vessel Operating.
Wt = Weight of Vessel Full.
Wp = Weight of Pier.
Ws = Weight of Soil.
Wf = Weight of Footing.
WE = (We + Ws + Wp + Wf)
WO = (Wo + Ws + Wp + Wf)
WT = (Wt + Ws + Wp + Wf)
e = Eccentricity = Pw·h2 / WE or Peg·h2 / WO
Piping
Insulation
Trays & Bubble Caps if Any
Platform
We, Wo, or Wt
Pw or Peg
Platform
Resultant
Ladder
We, Wo, or Wt
No. Number of Bolts
Wp
Ws
Wf
Compression Over Entire Base.
Resultant of Forces Inside of Kern.
Compression Over Part of Base.
Resultant of Forces Outside of Kern.
Figure 1
Figure 2

*Presented before California Natural Gasoline Association, Los Angeles, September 2, 1943.

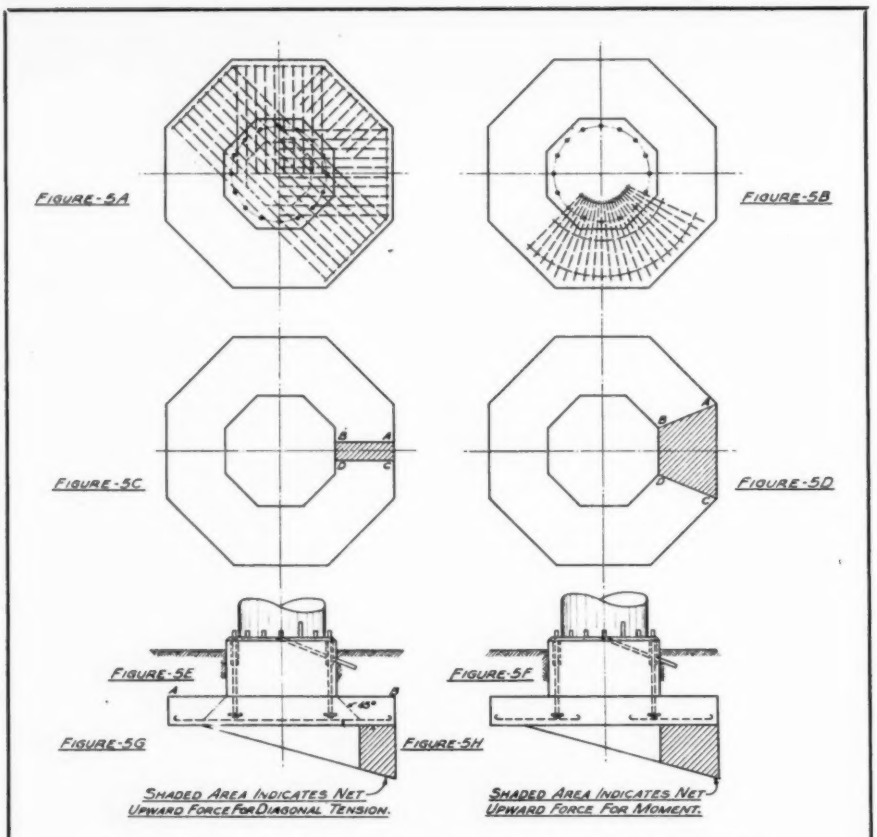


Plate 2. Typical octagonal footings, design and detail sketches

a reinforced concrete or steel frame of rigid type is designed. This type of structure with footing must satisfy all the conditions as required for a simple footing.

Design of a simple octagonal footing for a vertical vessel. All information concerning the weight of vessel (empty, operating, or full), and weight of such incidentals as piping, platforms, insulation, etc., should be known. It is necessary also to have all data on depth of footing, soil pressure, wind load, seismic force, and the maximum allowable concrete and steel stresses.

Design of anchor bolts. An allowable stress of not less than 12,000 lb. per sq. in. and not more than 15,000 lb. per sq. in. should be used for the bolt; and bolt sizes ranging between 1 in. minimum to 2½ in. maximum should be used. This range in allowable stresses facilitates the selection of the correct size bolt for the minimum or maximum circumferential bolt spacing. This low stress also allows for any corrosion. No allowance for reduction in initial tension need be made. The initial tension must be overcome by the stress due to wind or seismic force before the bolt will take any additional stress. For example, let us assume the initial tension due to tightening the bolt developed 15,000 lb. and suppose the stress in the bolt due to overturning moment developed 15,000 lb. So long as the initial tension has not been overcome, plus the weight of vessel, the maximum stress in the bolt will still be only 15,000 lb.

Wind moment or seismic moment for the design of bolts (see Fig. 2): Moment at base of vessel, M = (PW or Peg)hi.

Assuming the neutral axis is always on the center line of bolt circle, the following is the general formula for the maximum stress per bolt: $\frac{P}{A} \pm \frac{Mc}{I}$

As we are interested only in the tension stress in the bolt, this formula becomes

$$\frac{Mc}{I} - \frac{P}{A}.$$

For wind and empty vessel this form changes to $\frac{4(PW \times hi)}{N \times Db} - \frac{WE}{N}$

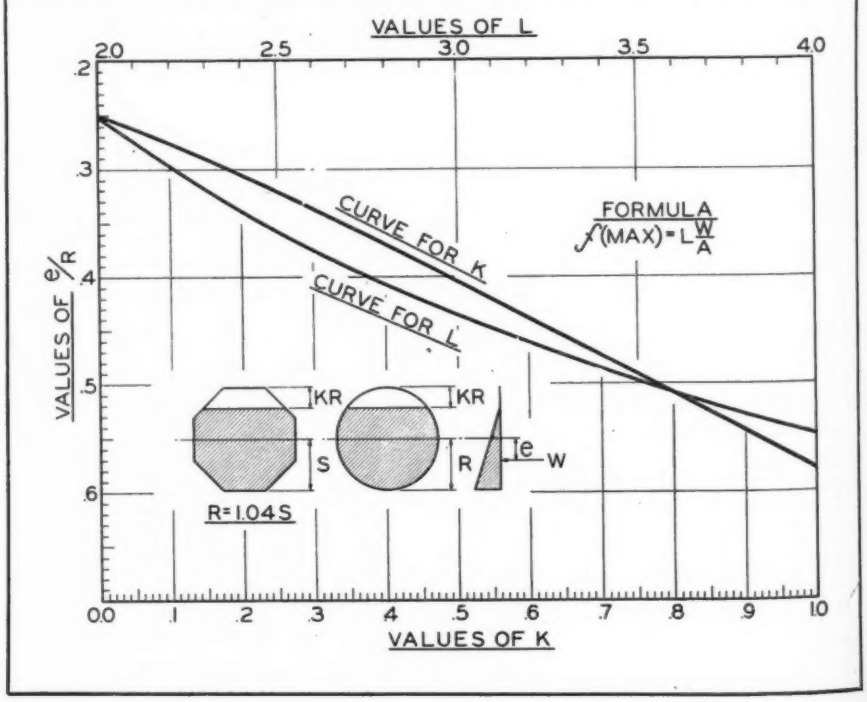
and for seismic and operating vessel the form changes to $\frac{4(Peg \times hi)}{N \times Db} - \frac{Wo}{N}$.

Whichever is maximum will give the stress per bolt.

Design for footing size. (a) Ordinarily under ideal conditions we would design a footing of octagonal shape, but in approximately 50 per cent of the cases, it is not possible to design an octagonal base, due to other equipment adjacent to the vessel, which might warrant a square or rectangular foundation. We will assume, however, that we are in this case designing an octagonal footing.

(b) First assume size of octagonal pier and the size of octagonal footing. The pier in most cases is assumed to be 18 in. larger than the diameter of the vessel. It is possible in estimating the size of the footing, you may have to make two or three assumptions before

Plate 3. Foundation pressures, round and octagonal bases. Values of K and L



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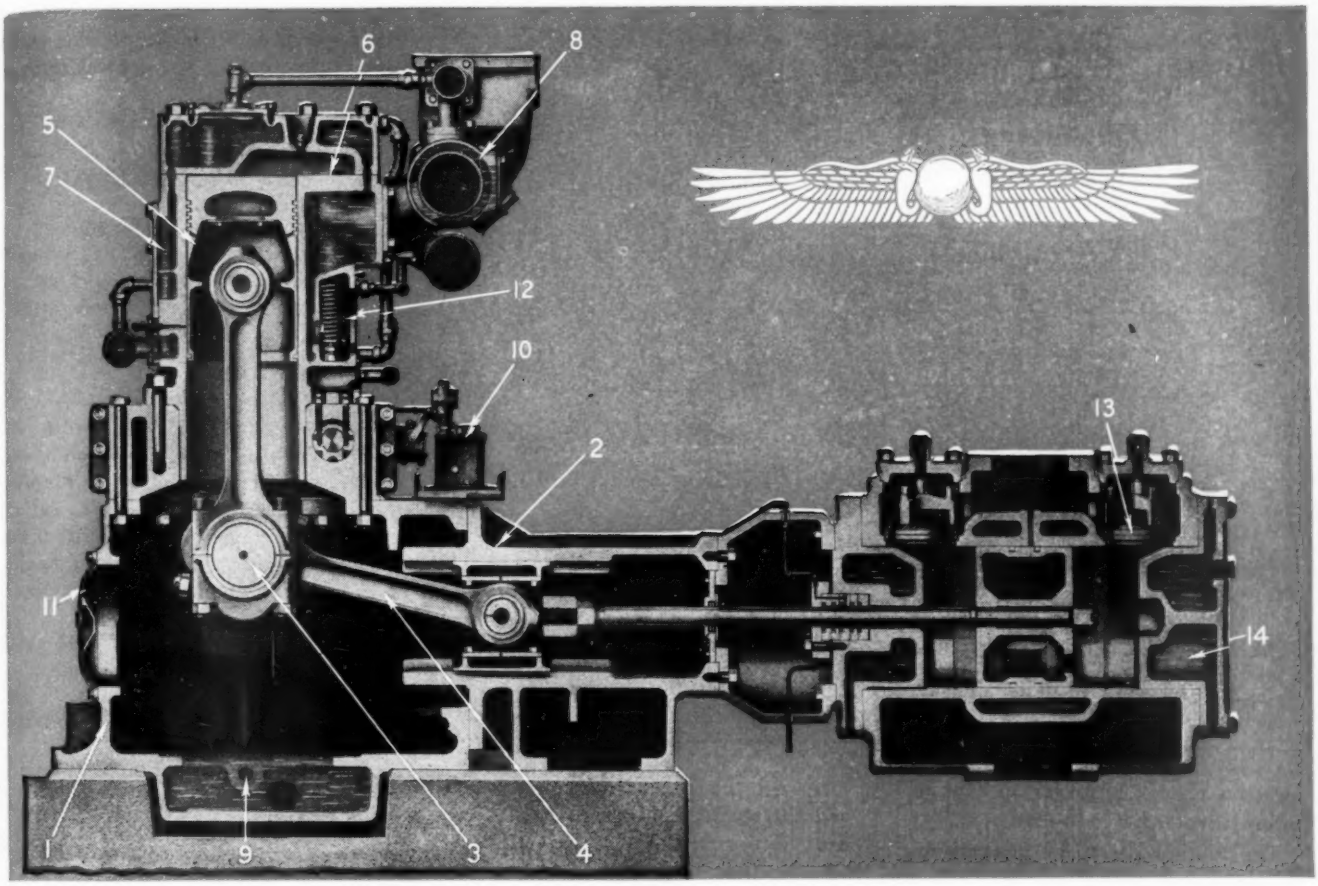

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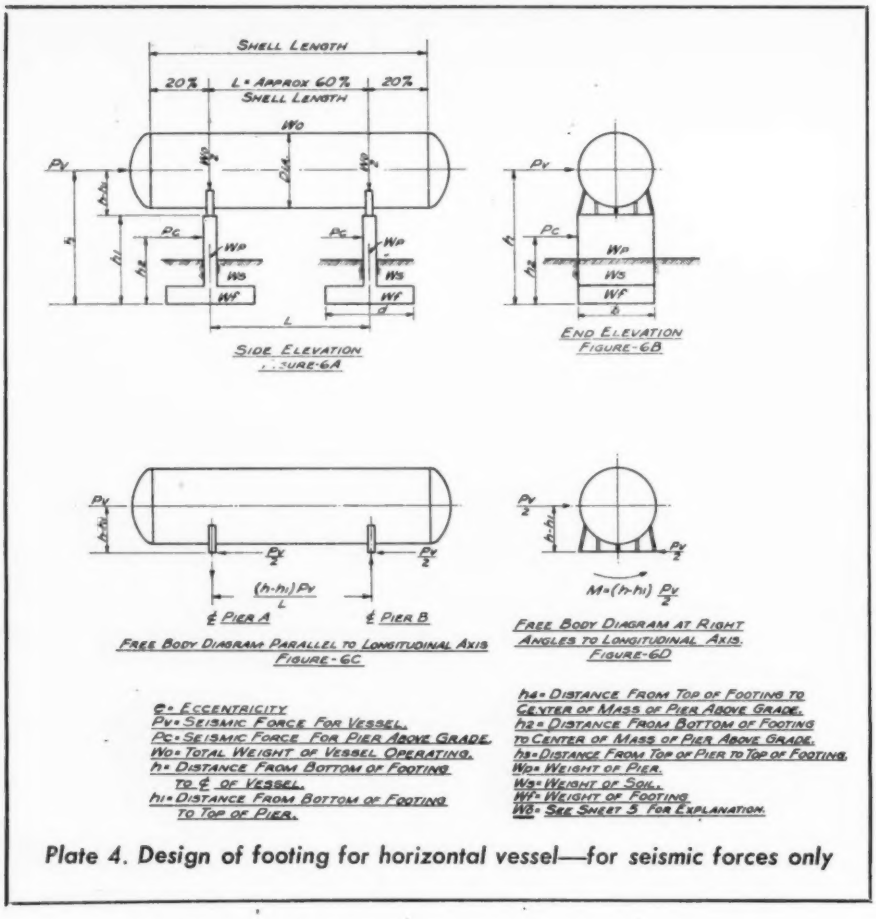

SHELL LENGTH
20%
L = APPROX 60%
SHELL LENGTH
20%
SIDE ELEVATION
FIGURE-6A
END ELEVATION
FIGURE-6B
FREE BODY DIAGRAM PARALLEL TO LONGITUDINAL AXIS
FIGURE-6C
FREE BODY DIAGRAM AT RIGHT ANGLES TO LONGITUDINAL AXIS.
FIGURE-6D
e = ECCENTRICITY
Pv = SEISMIC FORCE FOR VESSEL.
Pc = SEISMIC FORCE FOR PIER ABOVE GRADE.
Wo = TOTAL WEIGHT OF VESSEL OPERATING.
h = DISTANCE FROM BOTTOM OF FOOTING TO ℄ OF VESSEL.
h1 = DISTANCE FROM BOTTOM OF FOOTING TO TOP OF PIER.
h2 = DISTANCE FROM BOTTOM OF FOOTING TO CENTER OF MASS OF PIER ABOVE GRADE.
h3 = DISTANCE FROM TOP OF PIER TO TOP OF FOOTING.
Wp = WEIGHT OF PIER.
Ws = WEIGHT OF SOIL.
Wf = WEIGHT OF FOOTING.
We = SEE SHEET 5 FOR EXPLANATION.

Plate 4. Design of footing for horizontal vessel—for seismic forces only

you have the right size for all the conditions involved.

The footing has to be designed for the maximum condition, that is, having a maximum soil pressure and a minimum stability ratio.

To satisfy the design three cases would be necessary:

Case 1. Vessel empty with wind or seismic, whichever is greater.

Case 2. Vessel operating with wind or seismic, whichever is greater.

Case 3. Vessel full or under test condition with no wind or seismic force.

To find moment at base of footing for both wind and seismic force.

Wind moment = Pw · h2

Seismic moment = Peg · h2

In case 3 you have satisfied the condition when the soil pressure does not exceed the maximum allowable. In cases 1 and 2 you have satisfied all conditions when the soil pressure has not been exceeded, and the stability ratio is not less than the stability ratio specified. This stability ratio is as follows:

$$\frac{\text{Resisting moment}}{\text{Overturning moment}}$$

or

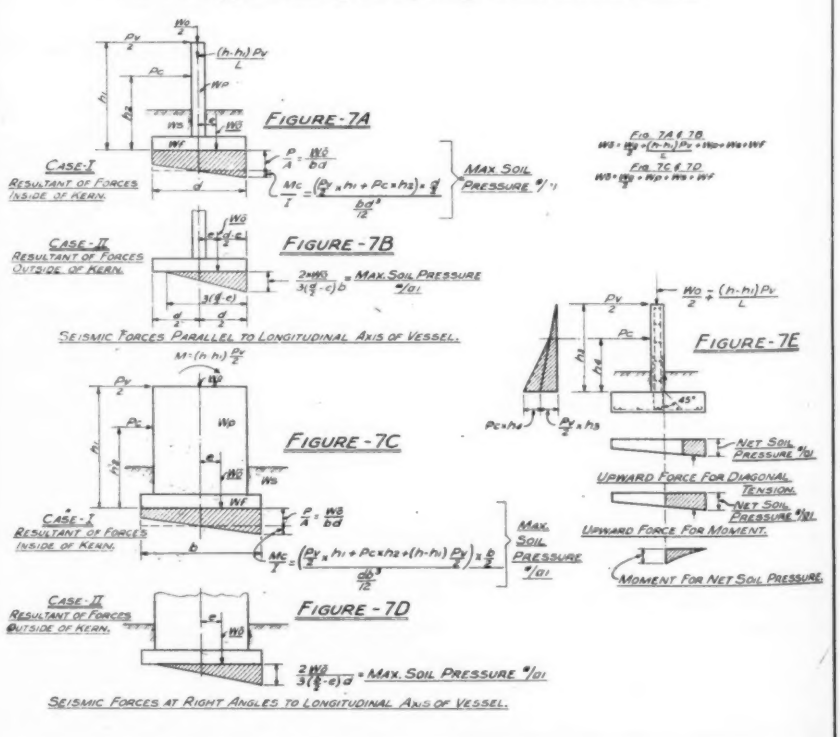
$$\frac{(\text{WE or WO})\ D/2}{(\text{Pw or Peg})\ H_2}$$

With a maximum allowable soil pressure and the stability ratio as specified the resultant may fall outside the Kern Section, therefore not giving compression under the entire footing. However, it seems a wasteful practice to design the footing especially for the unusual circumstances of an earthquake or tornado, which may occur once in the life time of the structure. It is not necessary to have compression all over the base as long as the stability ratio is that specified. With compression under the entire footing the general formula

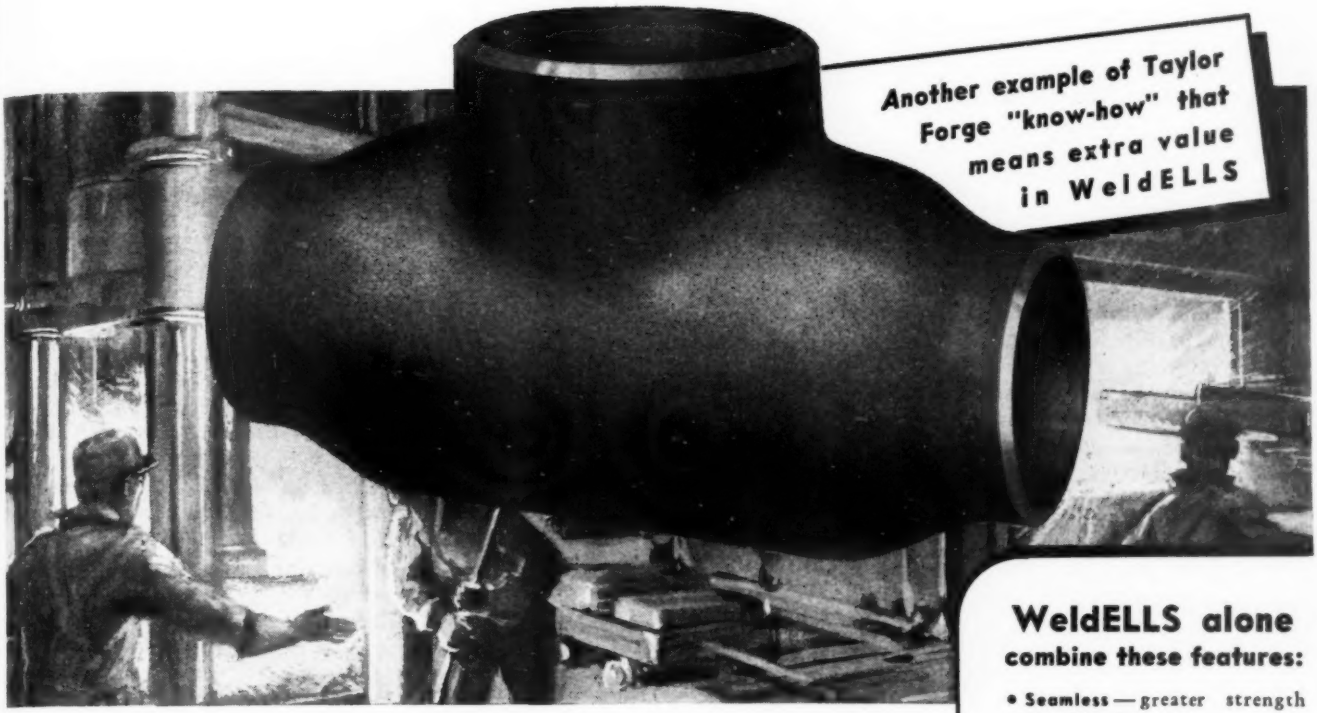
$$\frac{P}{A} \pm \frac{Mc}{I} \text{ is correct.}$$

$\frac{P}{A}$ is always as large or larger than $\frac{Mc}{I}$ (See Plate 1, Fig. 1.) With compression over part of the footing and since there can be no tension between the concrete and earth, the general formula $\frac{P}{A} \pm \frac{Mc}{I}$ would not satisfy this condition. (See Plate 1, Fig. 2.) A curve has been developed by Hool and Kinne, one for a square base with wind or seismic perpendicular to side, one for wind or seismic parallel to diagonal, and another for a round footing. With a few changes the curve for a round footing can be used for an octagonal footing. (See Plate 3.) The computations are fairly simple for a square footing with wind perpendicular to the side. (See Fig. 7B, Plate 5.) $\frac{P}{A} \pm \frac{Mc}{I}$ is not true in this case. The maximum soil pressure, lb. per sq. ft. $= \frac{2\,Wo}{3\,(\frac{d}{2}-e)\,b}$

Plate 5. Typical design of footing for horizontal vessels



RARE SPECIMEN IN WELDING TEES—



● *When you think of a reducing tee you always picture it as reducing in the branch. But this one, for the peculiar purpose it serves, had to be made the other way around. It's a seamless, carbon-moly forging, five inches in the run with a seven-inch branch—an "increasing" tee, so to speak; one more example of those kinks that are found so abundantly in the Taylor Forge bag of tricks.*

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It means that in developing WeldELLS we did not have to ask what kind of fitting is easiest to manufacture. Instead we asked what comprises the ideal fitting, and then, with every special facility and process at our command, made that conception a reality.

That is why WeldELLS have tangents . . . why they have extra reinforcement where service stresses are greatest . . . why they have such extremely accurate dimensions . . . why they have the features listed opposite . . . why, in short,

WeldELLS have everything

WeldELLS alone combine these features:

- **Seamless** — greater strength and uniformity.
- **Tangents**—keep weld away from zone of highest stress—simplify lining up.
- **Precision quarter-marked ends**—simplify layout and help insure accuracy.
- **Selective reinforcement** — provides uniform strength.
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- **Wall thickness never less than specification minimum**—assures full strength and long life.
- **Machine tool beveled ends**—provides best welding surface and accurate bevel and land.
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Wo = total vertical load,
e = eccentricity, and
b = width of footing.

This condition becomes a little more difficult for footings other than square or rectangular.

All allowable stresses in footings are generally increased 33⅓ per cent for wind or seismic forces. For test condition the allowable stresses should not be exceeded.

Method of reinforcing octagonal footing. The method of reinforcing the base should be given some consideration. Sketches 5A and 5B, Plate 2, show four-way reinforcing and radial reinforcing. For large footings there is a saving of approximately 25 per cent in steel in favor of radial reinforcing. The radial reinforcing is limited to the size of the footing. In case the pier is small there would be overlapping of reinforcing bars, which would make it too conjested to be practical. The pier should be large enough that it would be possible to extend the bars in from the face of the pier to develop bond and still have clearance between the bars for the aggregate. The depth of the footing for the radial reinforcing would be greater than for the four-way. In sketch 5C the shaded area indicates the area used for the moment for the four-way as against the shaded area in sketch 5D for the moment for the radial reinforcing. By inspection you will note that there is a greater force at sketch 5D for the width B-D than at sketch 5C for its width B-D, therefore the radial reinforcing requires a larger d (effective depth) for the same K value. There would be some gain for the radial reinforcing due to the fact that there is a 3-in. clearance between the earth and the underside of reinforcing bar. If, however, four-way reinforcing is used, approximately 2 in. more should be deducted for the total depth.

Sketches 5E and 5F indicate bottom reinforcing. In my opinion top reinforcing should be eliminated especially during the war crisis. A substantial saving of steel can be made by using the national emergency specification of the War Production Board. By making the depth of footing large enough so that the concrete does not exceed the allowable tensile value, the top steel can be eliminated. The tensile value of concrete is 0.04fc according to the emergency specification with an allowable increase of 33⅓ per cent for wind or seismic forces.

At point A of sketch 5E there will be no soil pressure with wind or seismic force acting, but the footing will have to be designed for a moment to take care of the weight of footing plus the weight of earth. In sketch 5g the shaded area indicates the upward force in the critical section for diagonal shear. In sketch 5h, the shaded area indicates the upward force for moment.

In some cases it is possible to design the pier or pedestal on a footing with a hollow center. This hollow space is later filled with earth on which is placed a concrete slab. If the pier and pedestals are made hollow, the supporting wall that forms the octagon should not be less than 18 in. thick. Obviously, an octagon less than 8 ft. O.D. would not be practical. There would not be room for men to construct forms. Furthermore, in order to make this type of construction practical the depth would have to be at least 6 ft. Otherwise the cost of form work would be greater than the saving of concrete. This type of construction necessitates more reinforcing in walls. The moment at the center of footing should be checked for a positive or negative when the hollow pier or pedestal is used.

Horizontal vessel. Footings for all horizontal vessels should be limited to two. The footing should be so spread that the stress at the center of vessel is the same as over the center of support. The footing should be set in a distance from the head seam approximately 19 per cent of total length of shell. This would give approximately 62 per cent of shell length between supports. Approximately 20 per cent or more of the inside upper surface may be in contact with vapors, whereas the lower surface will be in contact with liquids. Since vapors are poorer thermal conductors than liquids the sun's rays cause the dry surfaces to become hotter than the wet ones. This variation in temperature tends to deflect or curve vessel at center and lift off intermediate supports if more than two supports. If vessel lifts off intermediate supports, naturally the end supports would take additional load, thereby increasing the soil pressure.

Expansion of horizontal vessels should also have some consideration. Many vessels operate under high temperatures. When the expansion is small there is no reason to provide for a roller. Generally a slide plate is provided at the free end. Where a roller is provided, the fixed end pier would have to be designed for the total seismic force parallel to longitudinal axis.

Placing both piers on one combined footing is more expensive than designing an individual footing for each pier. For combined footing it would be necessary to have both top and bottom reinforcing to take care of the moments. In a single footing reinforcing is only necessary at the bottom of slab.

Design of footing for horizontal vessel. Fig. 6A shows all the forces acting on pier A and pier B parallel to longitudinal axis. Fig. 6B shows all the forces on pier A or pier B, at right angle to longitudinal axis. Fig. 6C shows a free body diagram of seismic forces on vessel parallel to longitudinal axis. Fig. 6D shows a free body diagram of seismic forces on vessel right angle to longitudinal axis. Fig. 7A shows all the forces acting on pier B, parallel to longitudinal axis and the resultant soil pressure. Cases 1 and 2 are self-explanatory. Case 1 is when the resultant force comes inside the Kern. Case 2 is when the resultant comes outside the Kern and still has a stability ratio as specified.

Fig. 7C shows all forces acting on pier B at right angles to longitudinal axis. Case 1 and case 2 for Fig. 7C and 7D are similar to case 1 and 2 of Figs. 7A and 7B.

Footing should be designed for maximum soil pressure.

Fig. 7E as noted, shaded area, indicated total net soil pressure or vertical upward force that produces diagonal tension stresses.

Fig. 7E as noted, shaded area, indicates total net upward soil pressure that produces moment in the footing.

At bottom of Fig. 7E is shown moment to design bottom slab.

To the right of Fig. 7E is shown total moment at base of pier. Pier should be designed for direct vertical load plus moment. This design would be the same as for a reinforced concrete column using a 1-ft. strip for the width.

Fig. 7E shows a typical method of reinforcing this type of footing.

—— ☆ ☆ ☆ ——

Corrosivity of Lubricating Oils

George W. Waters and Hugh D. Burnham, both of Shell Oil Company, Inc., presented a report on corrosivity of lubricating oils before the American Chemical Society, division of petroleum chemistry, Detroit, Michigan.

Bearing corrosion is analyzed into two concepts: "existent corrosivity," which occurs by virtue of the instantaneous chemical state of a lubricant, and "potential corrosivity," which occurs under conditions, representative of those of service, which lead to the simultaneous oxidation of the oil. The effects upon both types of corrosivity of temperature, time, nature of oil, concentration of reactants, and physical factors of tests are described in the paper. The important function of protective lacquer films in preventing corrosion and the interference with their action by detergents are demonstrated.

Recent Developments in TCC Processing*

By T. P. SIMPSON, L. P. EVANS, C. V. HORNBERG, and J. W. PAYNE
Socony-Vacuum Oil Company, Inc.

A. Catalysts

Clay catalyst. The catalyst now being used in commercial TCC units is produced from natural clays. The catalyst may be in the form of granules or pellets (Fig. 4) and, broadly speaking, covers sizes ranging from about 4- to 60-mesh. Improvements in manufacturing methods have resulted in the production of coarser and more rugged types of clay catalyst, and the materials now used commercially fall in the range of about 4- to 10-mesh size.

The use of clay catalysts offers certain advantages, including their availability in large quantities and relatively low cost. These are important considerations in the present emergency in view of the urgent need for large volumes of catalyst required to charge the various TCC units now being rushed to completion. These catalysts also are attractive for certain special applications, as in TCC operations conducted primarily for high butylene production.

Bead catalyst. The general advantages of using the more active, though more expensive, synthetic-type catalysts in place of clay catalysts have long been recognized. Until recently, however, the available synthetic materials have not had suitable physical characteristics, notably with respect to attrition resistance, to justify their use in TCC units. This prompted Socony-Vacuum to undertake extensive research work on synthetic catalysts. The ultimate result of this work was the invention of a new material, known as the "bead" catalyst, which is unique in shape (see Fig. 4), and is outstanding with respect to both physical ruggedness and catalytic activity. This catalyst derives its name from the fact that it is produced in the form of small spherical particles resembling translucent glass beads.

The phenomenal ruggedness and resistance to attrition which this catalyst possesses can be demonstrated in many ways. An individual bead with a diameter of ⅛ in. will support an average load of about 200 lb. and a mass of beads in a column will support a load of about 3000 lb. per sq. in. before crushing. In a jet test, where the beads are carried in an air stream at a velocity of 100 ft. per sec. and impinged against a vertical steel plate, they show no breakage and only 3 per cent wear after passing through 90,000 cycles. We have not been able to find any cracking catalyst which approaches the beads in regard to either strength or resistance to wear.

The composition or method of manufacture of this catalyst cannot be disclosed at this time.

B. Equipment Modifications

Reactors. Commercial TCC reactors were originally designed with an internal baffle system to provide high throughput capacity combined with efficient contact between oil vapors and catalyst. However, with this design the proportion of the total reactor volume occupied by the catalyst is reduced by the presence of the baffle system. Moreover, the quantity of the catalyst in the unit cannot be varied to provide maximum flexibility. Thus, although reactors of this type can be designed to operate at any specified space velocity, they cannot be operated below the designed space velocity without decreasing oil throughput rate. The first commercial TCC reactors being installed are of the baffled type, and will be operated on gas-oil cracking with clay catalyst which may later be changed, however, to the synthetic bead catalyst.

Recent catalyst developments have made it possible to design reactors of high throughput capacity which require no baffle system for obtaining intimate contact between oil vapors and catalyst. The elimination of internal baffling increases the effective volume of the reaction zone, and permits wide flexibility with respect to space velocity. All of

(Continued on Page 226)

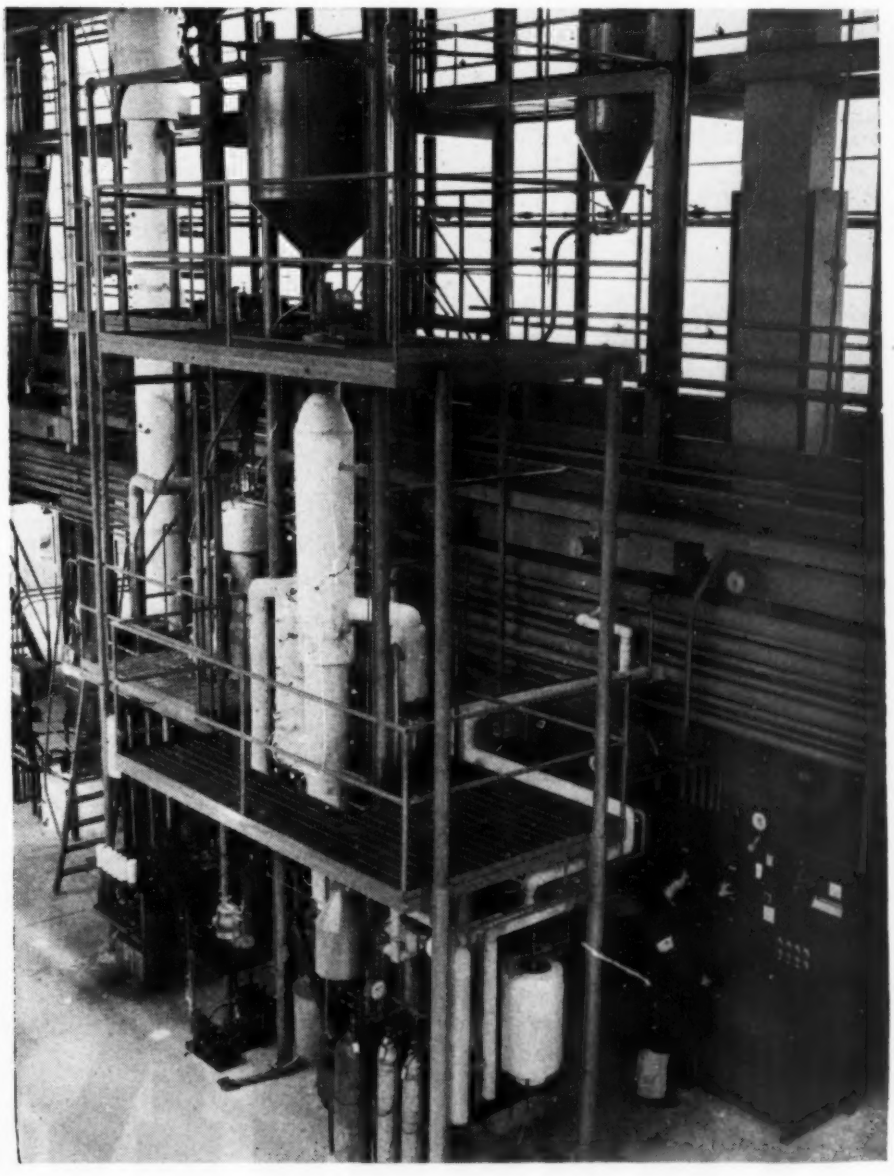
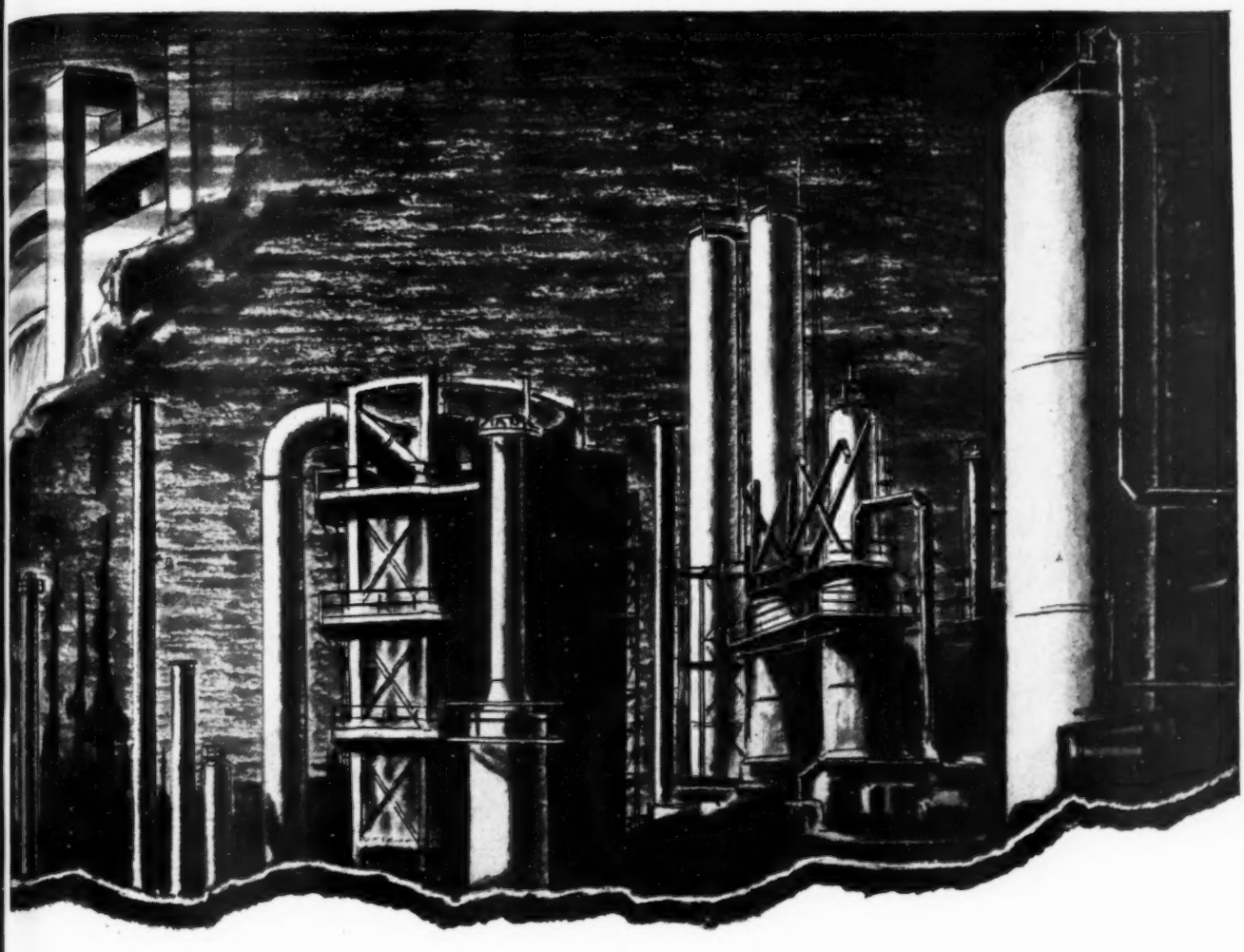


Fig. 1. Typical laboratory TCC pilot plant

*Presented before American Petroleum Institute, Chicago, Illinois, November 11, 1943.

BIG JOBS MEAN BIG THINKING



The stupendousness of this war has upset old senses of proportion and dwarfed former scales of operation in most every kind of enterprise.

The 5000-barrel petroleum refining unit — a sizable job only a few years ago — finds itself a Lilliputian among today's 60,000-barrel to 90,000-barrel Gullivers. Synthetic rubber production has risen from an experimental plaything to a giant industry. Plants and units in the chemical processing industries are decisively bigger.

Setting up these large-scale manufacturing facilities has naturally required "bigger" thinking. Plans, process engineering, design, and the application of new methods involve entirely new considerations.

No longer, in looking toward expansion, can the average operator's engineering department be expected to possess all the desirable background to undertake alone the job of important new plant construction or modernization. For no matter how large or small the plant, its pattern must embody the means for meeting the competition of the modern war-built giant.

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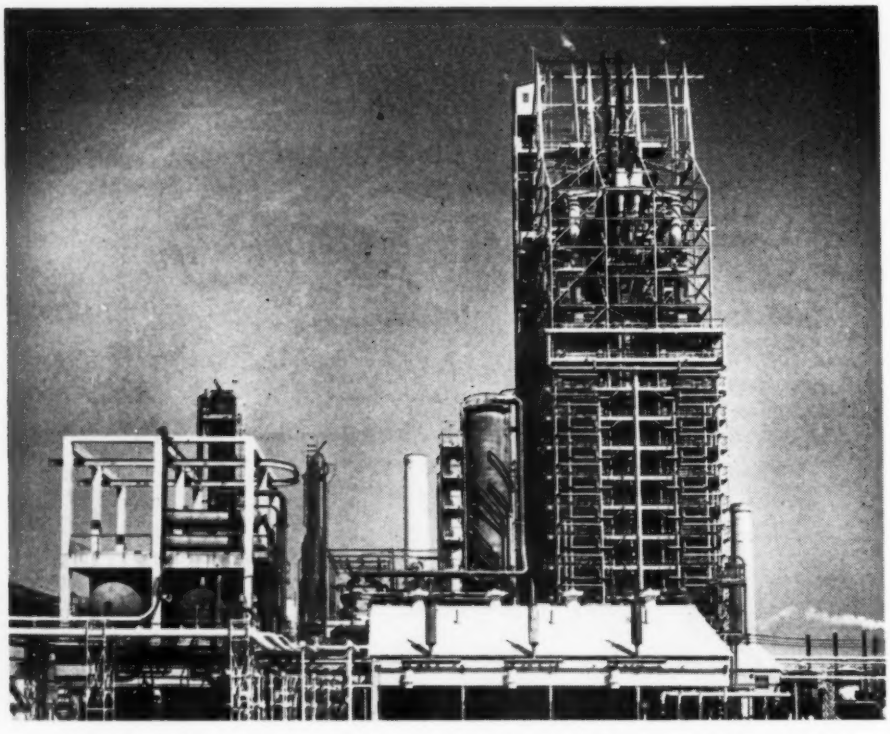

Fig. 2. Commercial TCC installation with two reactors and regenerators. Capacity, 20,000 bbl. of gas oil charge per day

(Continued from Page 223)

the recent commercial TCC reactors are of this improved type. As an added feature of flexibility, the reactors can be adapted to either countercurrent or concurrent flow.

Catalyst feed system. The catalyst feed system of present TCC units is designed to permit continuous flow of catalyst from the atmospheric part of the unit into the reactor, which operates at pressures up to 15 lb. per sq. in. gauge. The system employed comprises a feed leg especially designed to provide maximum operating pressure for a minimum leg height.

Kilns. The thermofor kiln described in last year's paper[1] is typical of that used successfully in the reactivation of spent fullers earth. This kiln is of the spiral finned-tube type employing a circulating molten-salt heat-transfer medium for temperature control.

The kilns in commercial TCC installations are of a radically different and simplified design. This new type of kiln is much cheaper to construct, more flexible in operation, and requires a minimum of alloy metals. Control of regeneration temperatures is excellent, and is achieved without recirculation of either flue gas or catalyst. The surplus heat developed in catalyst regeneration is utilized to produce high-pressure steam. The kiln operates at substantially atmospheric pressure, and requires only low-pressure blowers to supply the regeneration air. The atmospheric-pressure operation eliminates the necessity of employing a catalyst feed leg as is necessary in the reactor.

Catalyst flow distribution. In order to secure a uniform contact between catalyst and vapors in TCC reactors and kilns, it is essential that the catalyst flow be uniform in all parts of the vessel. This has been achieved by means which also effect a convergence of the catalyst flow to one outlet point, thus permitting the use of a single drawoff pipe.

C. Products

The improvements in the TCC equipment and catalysts discussed hereinbefore have been paralleled by equally important developments in the application of TCC processing to the catalytic conversion of petroleum fractions. At present the TCC process is playing a vital rôle in the manufacture of high-octane aviation gasoline, of butylenes for the production of synthetic aviation blending agents and synthetic rubber, and of other essential war products. After the war TCC plants also will be utilized for the production of motor gasoline.

The application of the TCC process to the production of aviation-base stocks was discussed briefly in last year' paper.[1] The original processing scheme comprised TCC cracking of gas oils over clay catalyst followed by once-through TCC treating of the resulting motor gasolines. This operation yields aviation-base stocks having leaded (4 ml) octane ratings ranging from 94 to 97 (AFD*-1C) depending on the nature of the gas-oil charge stock. Moreover, the aviation-base stocks require little or no finishing treatment to meet gum, color, and sulphur specifications.

As a result of recent developments, substantial improvements have been made in the application of the TCC process for the production of aviation-gasoline-base stocks. Chief among these developments are:

a. The invention of the bead catalyst described previously herein.
b. The application of improved processing techniques in the treating step.
c. The extension of TCC processing to include a wide variety of charging stocks, other than gas oils,

*Aviation Fuels Division, CFR committee.

TABLE I

Properties of typical aviation gasolines from TCC processing of gas oils over clay catalyst

Source of gasoline	Naphthenic gas oil		Paraffinic gas oil		High-sulphur gas oil treating
Process	Cracking	Treating	Cracking	Treating	
Properties of 7-lb. aviation gasoline:					
Gravity, deg. A.P.I.	63.1	56.5	67.7	60.9	60.1
Reid vapor pressure, lb	7.1	7.2	7.0	7.0	6.9
Doctor test	Negative	Negative	Negative	Negative	Negative
Mercaptan-sulphur test	Negative	Negative	Negative	Negative	Negative
Acid heat, °F	67	12	92	14	35
Bromine No.	37.2	4.6	46.1	6.6	17.9
Sulphur, per cent by weight	0.026	0.022	0.025	0.021	0.061
Accelerated 5-hr. gum, milligrams per 100 ml:					
Inhibited and leaded	....	2	....	4	5
Octane No. (AFD-1C):*					
Without addition of TEL	75.8	81.9	74.4	79.4	79.0
Plus 3 ml. TEL per gal	87.3	95.9	85.1	94.3	91.7
Plus 4 ml. TEL per gal	89.5	97.7	87.5	96.3	94.0
ASTM distillation, °F:					
Initial boiling point	108	106	106	105	107
5-per cent point	131	131	130	129	128
10-per cent point	139	140	138	140	136
20-per cent point	150	154	150	153	148
30-per cent point	164	169	165	165	160
40-per cent point	181	188	180	182	180
50-per cent point	200	207	198	200	202
60-per cent point	216	228	213	223	227
70-per cent point	230	246	224	243	250
80-per cent point	245	263	239	259	268
90-per cent point	264	278	260	277	284
End point	304	302	302	305	320
Recovery, per cent by volume	98.5	98.0	98.0	98.0	98.5
Loss, per cent by volume	0.5	1.0	1.2	1.0	0.7

*AFD-1C=1C method, Aviation Fuels Division, C.F.R. committee.

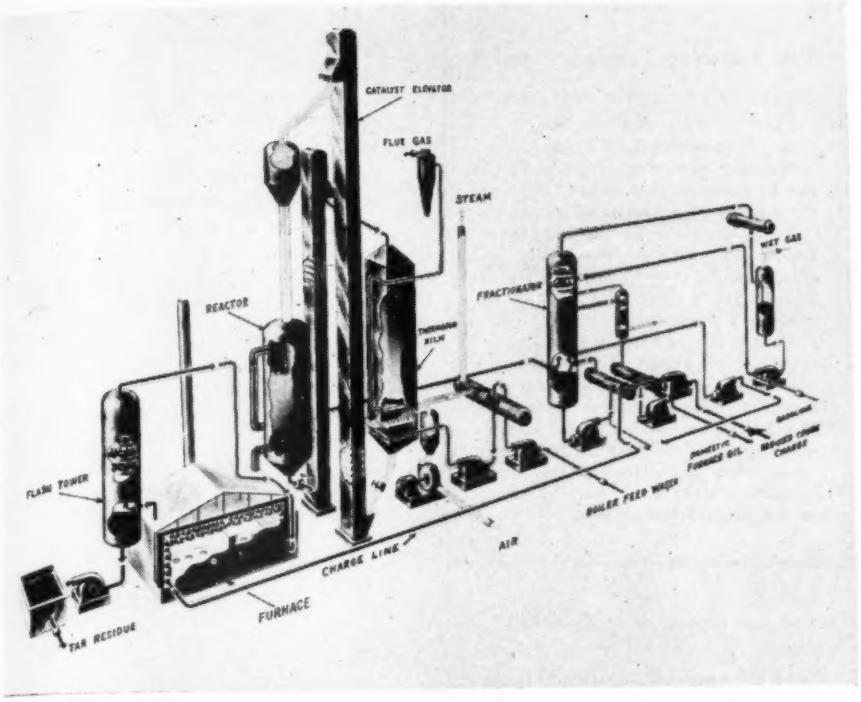

Fig. 3. Flow diagram of TCC process

well suited for aviation production.

Bead catalyst is the most important of these developments, and makes possible significant gains in the manufacture of aviation-base stocks. With respect to the present aviation-fuel program the substitution of bead for clay catalyst will permit a large increase in plant output or a substantial rise in quality level.

Although bead catalyst produces aviation base stocks of exceptional quality in conventional multi-pass operation, its performance in one-pass operations is equally striking. For example, by one-step processing of properly selected charge stocks over bead catalyst it is possible to produce good-quality aviation-base stocks for direct blending in high-grade aviation gasolines. This provides considerable flexibility in processing, and may be translated into substantial economic advantages either for wartime or postwar operations.

Further improvement in two-pass processing technique for the production of aviation-gasoline-base stocks has been made possible by combining the advantages of the bead catalyst and the new type reactor. Briefly, the improved technique results in greater yield per unit volume of charge stock, greater production per unit of TCC capacity, and higher quality of the product.

The application of catalytic cracking for motor and aviation-gasoline production has been based almost exclusively on the utilization of gas oils as charging stocks. With the current emphasis on aviation fuels, it is only natural that efforts should be directed toward finding additional sources of charge stocks especially suited for aviation-gasoline production. Recent TCC development work has demonstrated the suitability of a number of stocks for this purpose—stocks which are common to many refineries but which have hitherto been diverted to motor gasoline or other products.

Among the most attractive of these stocks are the light and heavy virgin naphthas. Catalytic reforming of these stocks in TCC units over bead catalyst produces exceptionally high yields of aviation-base stocks having leaded octane ratings of 98 to 100 (AFD-1C). Moreover, the products have well-balanced boiling ranges, and meet all other aviation-gasoline specifications; hence, they may be considered as excellent aviation fuels by themselves, being equal to or superior to alkylate and similar synthetic fuels in many respects. The processing conditions required to obtain the optimum results vary according to the boiling range of the charge stock, but the TCC process has adequate flexibility to meet any choice of conditions without loss in efficiency or throughput capacity. Thus the TCC process opens up still another field of processing which can be done more effectively by catalytic than by conventional thermal means.

In addition to virgin gas oils and light and heavy naphthas, the range of potential charging stocks suitable for TCC processing to aviation gasoline has been extended to include a variety of processed naphthas. These include products obtained by thermal reforming, polyforming, and hydroforming of virgin naphthas. Such stocks may be TCC-processed either over clay or bead catalyst to yield high-quality aviation-base stocks.

Thus far the developments incorporated in the TCC process have been discussed primarily from the standpoint of improving aviation-gasoline production. However, the improvements are of a basic nature and, therefore, enhance no less the value of the process for motor-gasoline production.

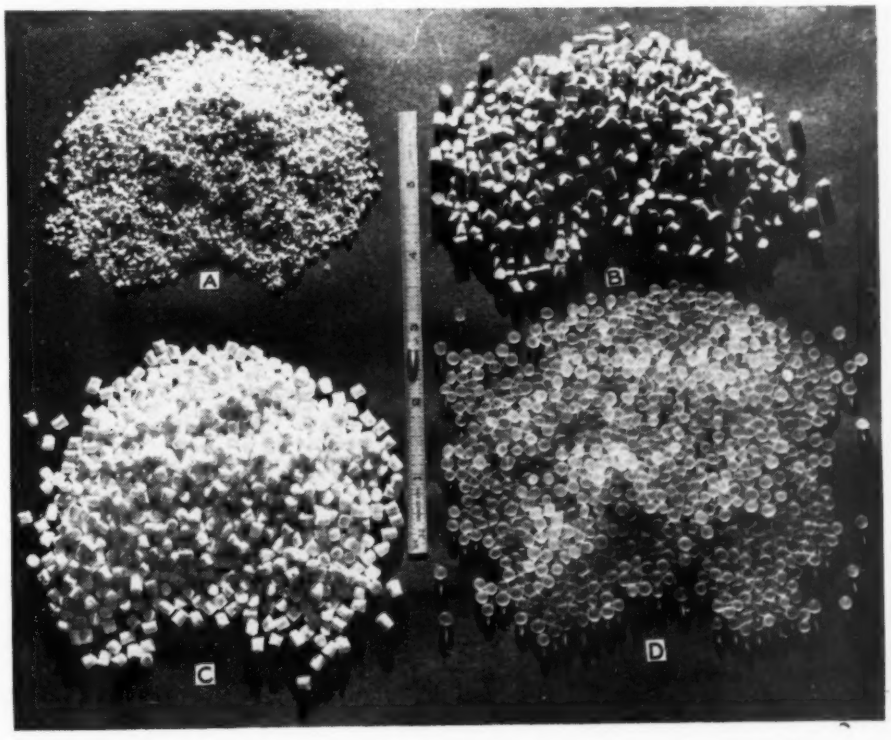

Fig. 4. Typical catalysts. A.—Clay granules. B.—Clay pellets. C.—Synthetic pellets. D.—Synthetic beads

As was pointed out in the previous paper,[1] motor gasolines of consistently high quality can be produced by TCC-cracking gas oils over clay catalyst. The clear CFR motor octane number of the motor gasolines normally produced in such operations ranges from about 77 for paraffinic to 82 for naphthenic stocks. However, both the yield and octane number of the gasoline can be varied somewhat by changing the severity of the operation. In this connection, it may be noted that the lighter the charge stock, the more severely it can be cracked within the coke-burning limits of the catalyst regeneration system of the TCC plant, thus permitting an added degree of flexibility with respect to the yield and quality of the gasoline produced.

With bead catalyst, it is possible to obtain still higher yields and quality of motor gasoline from a given cracking stock. The improvement in yield by substitution of bead for clay catalyst is directly related to the higher activity of the bead catalyst, while the CFR motor rating of the product is several octane numbers higher than that from comparable operations on clay catalyst. As applied in TCC processing, bead and clay catalysts are both good desulphurizing agents, with a slight advantage in favor of the beads. Motor gasolines from bead-catalyst operation are also of considerably better volatility than from clay. The overall advantage of the bead catalyst in terms of increased production, saving in tetraethyl lead, and reduced finishing costs thus marks a high standard of performance in the field of catalytic processing for the production of motor as well as aviation gasolines.

Many of the developments made in connection with utilization of charge stocks other than normal boiling-range gas oils for aviation-gasoline production apply equally to motor gasoline. For example, preliminary but unpublishable data indicate attractive possibilities for TCC reforming of certain straight-run naphthas and viscosity-breaker gasoline for motor-gasoline production. In addition, the TCC process can be adapted to the conversion of low grade stocks of high boiling range, such as are obtained from crude reduction, viscosity-breaking, and coking operations, into motor gasoline and other useful products.

The TCC process also can be applied to advantage in refineries already having installed catalytic capacity (of the TCC or any other type) to increase their production of aviation or motor gasoline by processing cycle stocks obtained as byproducts from existing catalytic cracking operations. Due to their greater refractoriness, these cycle stocks produce somewhat lower gasoline yields than the corresponding virgin gas oils, but the products are of high quality.

Reviewing these various developments, it is evident that the TCC process now offers the unique possibility of utilizing substantially all crude distillate fractions to produce high-octane aviation-base stock and useful byproducts, with little or no auxiliary processing other than fractionation. In the manufacture of motor gasoline the same latitude in choice of stocks exists and, in addition, the output of motor gasoline from a given TCC unit is much greater than that of aviation gasoline due to the wider boiling range of the product and the elimination of treating operations. This broad application of the TCC process involves utilization of stocks from paraffinic, naphthenic, and mixed-base crudes of both low and high sulphur content. The process is thus destined not only to play a vital rôle in supplying the present and future high-octane fuels, but also will be an important factor in conserving our petroleum resources. This is now well recognized by the petroleum industry at large, and is reflected in the following list of major oil companies now employing or installing thermofor catalytic cracking units:

1. Magnolia Petroleum Company
2. Gulf Oil Corporation
3. The Pure Oil Company
4. Sinclair Refining Company
5. General Petroleum Corporation.
6. Continental Oil Company
7. Crown Central Petroleum Corporation
8. Ashland Oil and Refining Company
9. Socony-Vacuum Lubrite Division
10. Richfield Oil Company
11. Union Oil Company of California
12. Socony-Vacuum Oil Company, Inc.
13. Standard Oil Company of California
14. Tide Water Oil Company
15. Sun Oil Company

The Foaming Tendency and Stability of Crude Petroleum

W. H. Somerton, University of California, presented a paper to the A.P.I., Chicago, November, 1943, on the foaming properties of crude petroleum. Methods of measuring foaming tendency and foam stability and of expressing the results of such measurements in readily comparable units are explained. Results were analyzed further to determine the influence of other physical properties of the crude-oil-gas foam systems on their foaming properties. Stability was found to be determined by the viscosity of the crude alone, whereas the tendency to foam appears to be more a function of the composition of the system.

TABLE 2

Properties of typical motor gasolines from TCC cracking of gas oils over clay catalyst

	Naphthenic* gas oil	Paraffinic† gas oil	High sulphur‡ gas oil
Properties of 10-lb. motor gasoline:			
Gravity, deg. A.P.I.	52.7	60.6	55.2
Reid vapor pressure, lb.	9.5	9.6	10.2
Doctor test	Negative	Negative	Positive
Mercaptan-sulphur test	Negative	Negative	Negative
Copper-dish gum, mg. per 100 ml.	10	16	20 §
Glass-dish gum, mg. per 100 ml.	2	1	5 §
Oxygen-bomb test, hours and minutes	8:30	12:30	....
Sulphur, per cent by weight	0.025	0.028	0.106
Octane No.:			
CFR motor method (without TEL addition)	82.0	76.9	78.6
CFR research method:			
Without TEL	92.0	84.1	85.0
With 1 ml. TEL per gal.	96.5	91.9	88.5
With 2 ml. TEL per gal.	98.5	93.7	90.1
With 3 ml. TEL per gal.	99.2	95.1	91.0
ASTM distillation, °F.:			
Initial boiling point	88	90	93
5-per cent point	110	110	118
10-per cent point	125	121	140
20-per cent point	156	145	168
30-per cent point	198	175	199
40-per cent point	237	209	237
50-per cent point	267	243	265
60-per cent point	294	276	297
70-per cent point	322	307	325
80-per cent point	346	337	350
90-per cent point	369	376	372
End point	410	404	404
Recovery, per cent by volume	97.5	97.5	97.5
Loss, per cent by volume	1.3	1.5	1.6

*Aniline point, 145 °F.
†Aniline point, 176 °F.
‡This charge stock has a sulphur content of 1.9 per cent by weight; aniline point, 154 °F.
§Gum values after inhibiting with one part of alpha naphthol for 5000 parts of gasoline.

Reference

1. "The Thermofor Catalytic Cracking Process," Simpson, Evans, Hornberg, and Payne, *Proc. A.P.I.* 23 [III] 59 (1942).

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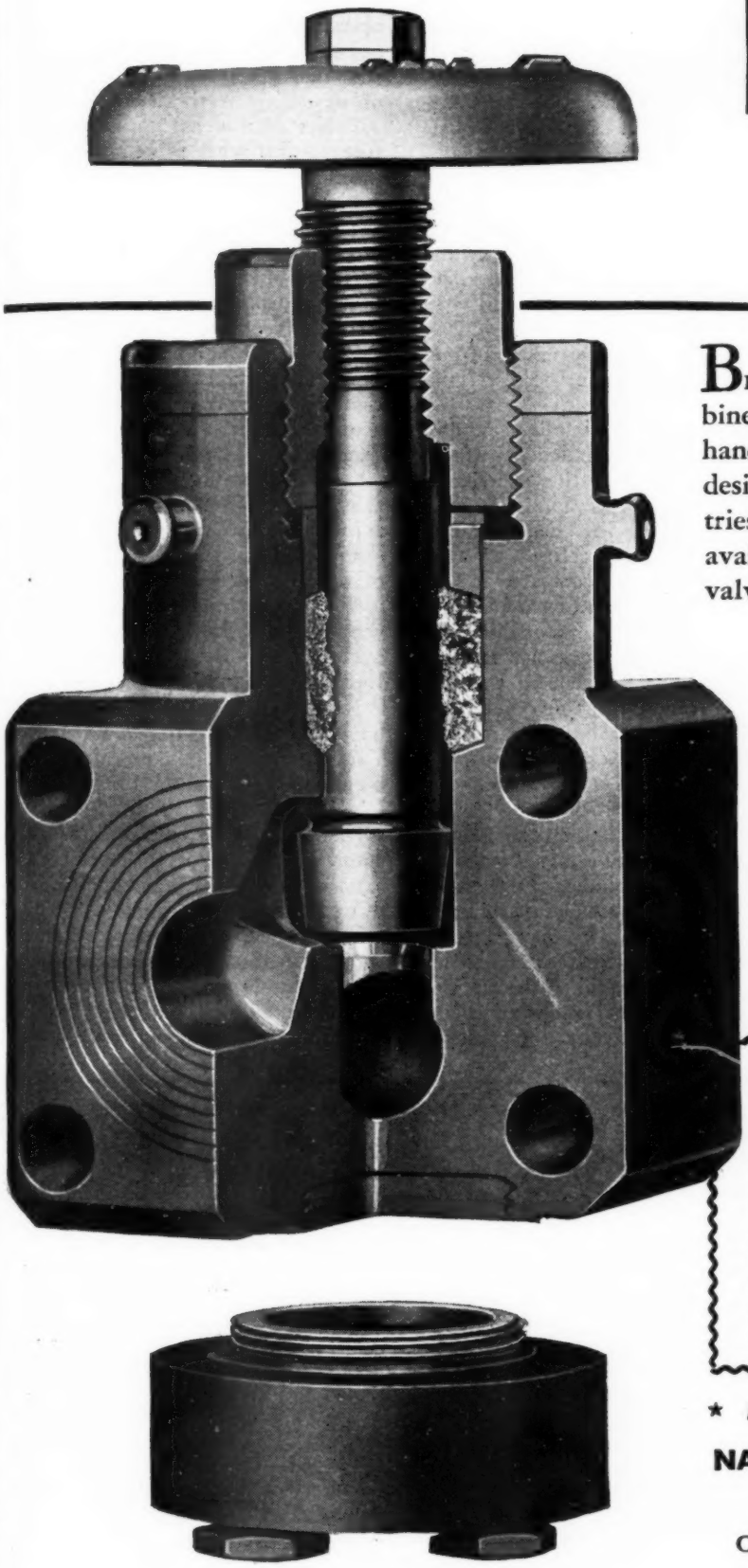

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Fluid Catalyst Cracking for Premium Fuels*

By E. V. MURPHREE†, H. G. M. FISCHER†, E. J. GOHR†, W. J. SWEENEY†, and C. L. BROWN‡

A NUMBER of large fluid catalyst cracking units are now in successful operation producing large quantities of war products. The latest of these, of simplified and improved design, was recently brought onstream. More than 30 of such plants are being completed in the United States and in foreign refining centers. Actively contributing to the prosecution of the war, each installation is now operating with the objective of providing maximum quantities of highly aromatic aviation-base stocks and raw materials for alkylate, as well as for synthetic-rubber and toluene production. These operations have established the fluid catalyst process as an economical basic cracking installation for producing aviation fuels, particularly in terms of critical material requirements. It is the purpose of this paper to present, insofar as war restrictions permit, some technical aspects and results of the commercial development of the fluid catalyst process, and to review typical applications of this process that have, or will be, made in the production of premium aviation and motor fuels.

Commercial history. The first commercial fluid cracking units to be put into operation were designed before the entrance of the United States into the present war, and were planned for normal peacetime production of premium motor fuels. Engineering design of the first of these was based on a background of experimental and semi-plant experience in continuous fluid cracking as well as in intermittent, fixed-bed operations. The first commercial plant was placed in operation at the Baton Rouge refinery of the Standard Oil Company of Louisiana.

Initial operations at the Baton Rouge plant of necessity were conducted for the production of motor gasoline employing a natural clay catalyst, inasmuch as the synthetic catalyst required for war-products operations was not available at that time. For a period of 54 days, heavy wide-cut paraffinic gas oils were processed continuously with but one short shutdown for routine equipment inspection. Performance of the plant in general was smooth, and was characterized by easy control of catalyst flow and process conditions. After synthetic catalyst had become available, and following minor revisions to the catalyst-recovery system, the unit was brought onstream for war-products production—subsequently operating continuously for five months without a shutdown. Currently, the Baton Rouge unit is operating once-through—producing butylenes for rubber and alkylation, in addition to light paraffinic and heavy aromatic aviation-gasoline components.

Two other fluid plants, of essentially the same design as the Baton Rouge unit, are in operation: One at the Baytown refinery of the Humble Oil and Refining Company, and the other at the Bayway plant of the Standard Oil Company of New Jersey—both producing alkylate feed stocks and aviation gasoline. The Bayway plant currently is producing aviation gasoline of higher quality by subjecting the material from the cracking unit to further catalytic processing.

New improved and simplified designs have been developed, particularly in the catalytic section. Operating experience to date with this type of unit, on full commercial scale, has demonstrated even greater flexibility and ease of control for this design as compared to the first. Upon completion of the planned installations of fluid plants of this general type, the installed capacity of fluid catalyst cracking will exceed that of any other catalytic cracking process.

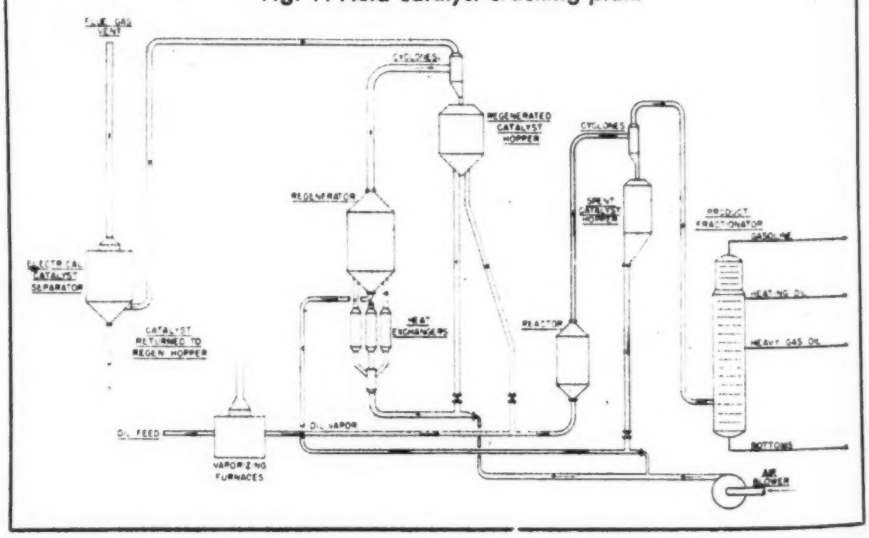
Typical commercial operating results, both process and mechanical, are presented and discussed in subsequent sections of this paper.

Description of commercial plant. Fluid-catalyst cracking plants embody a new chemical engineering technique wherein solids are handled in a "fluid," or freely moving, state such that a solids-mass can be circulated much in the same way as a liquid. A description of this technique was published in an earlier article. Practically, the application of this technique in the catalytic cracking of petroleum has resulted in substantial simplifications in design, and operating ease over conventional fixed-bed processes, and also has imparted to the fluid-type catalytic plants a degree of flexibility in control of operating variables such as has not been heretofore possible with either the fixed- or the moving-bed type of catalytic plants. A simplified flow diagram illustrating the essential features of the first commercial fluid catalyst plant design is presented in Fig. 1.

A fluid plant, as indicated in the diagram, is composed of essentially three sections: viz., cracking, regeneration, and fractionation. The cracking reaction takes place continuously in one reactor, the spent catalyst being removed (and replaced) continuously for simultaneous regeneration in a separate vessel. Continuity of flow of catalyst, as well as of oil, thus is accomplished—with the result that the characteristic features of fixed-bed designs involving the intermittent shifting of reactors through cracking, purging, and regeneration cycles are eliminated. The flow through the plant is as follows:

Regenerated catalyst from a storage hopper flows by gravity down through a standpipe wherein a pressure head is built up on the catalyst. The latter then is injected into the fresh oil vapor which carries the catalyst to the cracking reactor. The velocity in the reactor is low so as to maintain a high concentration of catalyst, and cracking occurs with a subsequent deposition of carbon on the catalyst. Although high concentrations of catalyst are obtained in the reaction vessel, the solid-gas mixture is extremely turbulent and resembles a boiling

Fig. 1. Fluid catalyst cracking plant



*Presented before American Petroleum Institute, Chicago, Illinois, November 11, 1943.

†Standard Oil Development Company.

‡Standard Oil Company (Louisiana).

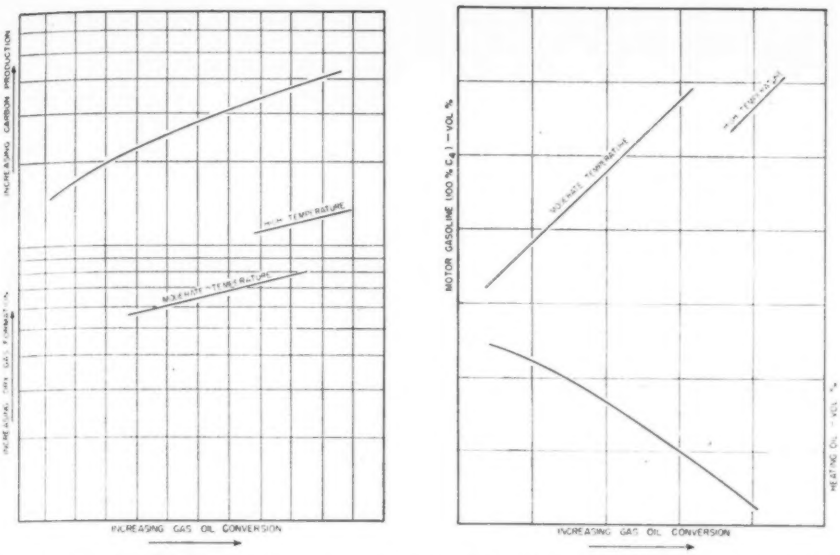


Fig. 2. Fluid catalyst cracking for motor fuel. Product distribution; commercial operations; natural catalyst; heavy paraffinic gas oil feed

liquid in many respects. The mixture of cracked products and spent catalyst from the cracking zone are separated in dust-recovery equipment. The cracked products flow to fractionating equipment for separation into desired components. The spent catalyst drops into a storage hopper, flows down a standpipe, is picked up by an undiluted air stream, and is carried to the regenerator in which carbonaceous deposits are removed by combustion. The mixture of flue gas and catalyst from the regenerator are separated, the catalyst dropping into the regenerated catalyst hopper to complete its cycle.

The heat evolved from the combustion of the carbon deposited on the catalyst is utilized to preheat gas-oil feed and also to produce steam. In order to avoid excessive temperature increase in the regenerator, catalyst is recycled through a separate standpipe and through oil coolers, as shown in Fig. 1. Subsequent development has indicated that it is feasible, moreover, to dissipate a greater portion of the heat of combustion to the preheating of fresh feed by introducing the hot catalyst directly into the cold oil, eliminating thereby the need for externally-fired vaporizing equipment.

Operation of the fluid cracking plant is virtually automatic. The rate of catalyst flow, for example, is controlled by a mechanism actuated by changes in the density of the catalyst-oil mixture. Flow of catalyst to regeneration is regulated by the level of catalyst in the spent-catalyst hopper. Similarly, regeneration temperature is governed by automatic control of the quantity of catalyst circulated through the heat exchangers.

Reaction temperatures can be varied by the quantity of heat applied to the oil in the furnaces and also very substantially by the amount of hot catalyst circulated. Liquid or vaporized stocks are processed with equal ease. In commercial operations, reactor temperatures have ranged from 800 to 1000°F. Regeneration temperatures similarly can be varied widely, and are maintained normally between 1000 and 1200°F. The depth of cracking may be governed independently of temperature by the ratio of catalyst to oil flow and by other process variables. Because of the method employed in handling the catalyst, exceptionally large amounts can be circulated, permitting great variation in the intensity of treatment. High cracking temperatures, above the range normally possible by other processes, are readily obtained through the high catalyst circulation in the fluid process. These features are of considerable importance, inasmuch as the character of products resulting from catalytic cracking is affected extensively by both temperature and conversion level.

Fig. 3. Fluid catalyst cracking for motor fuel. Product quality; commercial operations; natural catalyst; heavy paraffinic gas oil feed

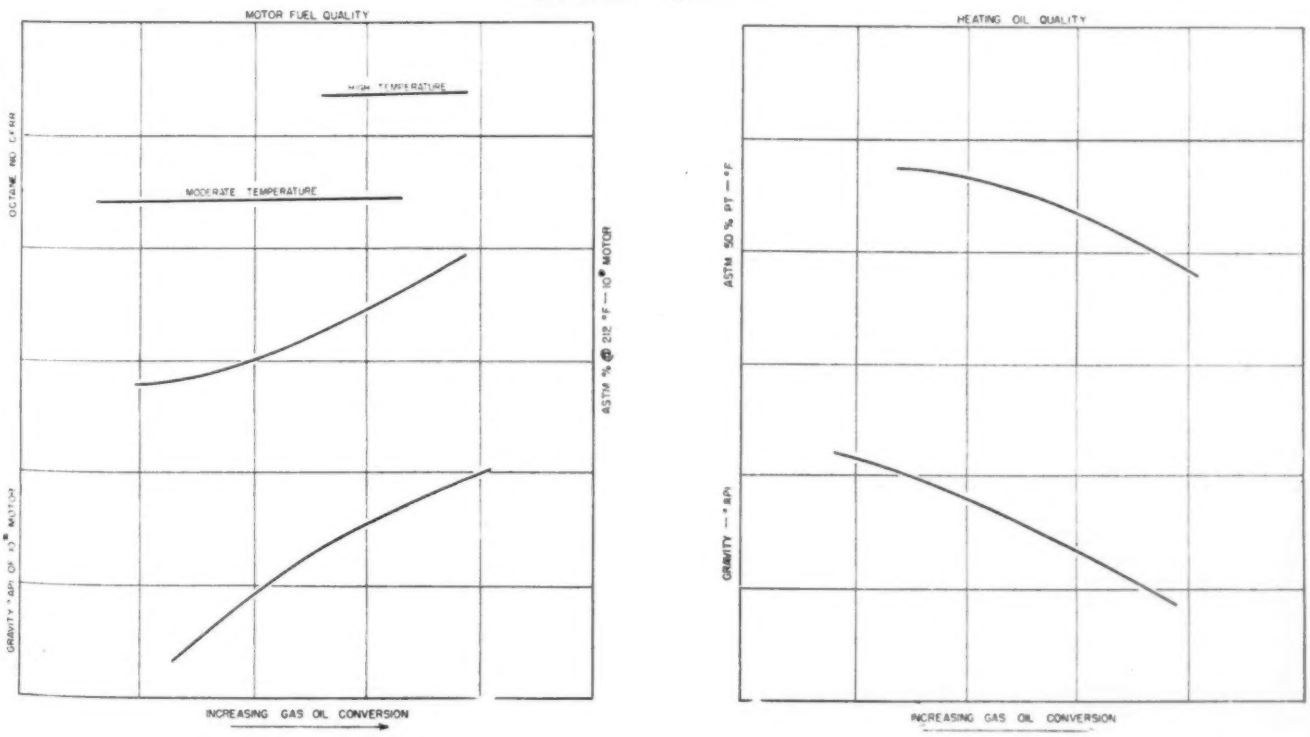


TABLE 1

Quality of motor fuel from commercial operation with synthetic catalyst

Feed properties	
Gravity, deg. A.P.I.	34.7
Initial boiling point, °F	412
50-per-cent-point, °F	586
End point, °F	752
Motor gasoline properties	
Gravity, deg. A.P.I.	55.0
Reid vapor pressure, lb	10.1
Sulphur, per cent by weight	0.04
Copper-dish gum, mg. per 100 ml	10
Breakdown, hr	13
Acid heat, °F	138
Initial boiling point, °F	93
Per cent over at:	
158 °F	27.0
212 °F	46.0
284 °F	64.5
90-per-cent point, °F	360
End point, °F	390
Octane No.:	
ASTM: with no addition of TEL	82.6
CFR-R: with no addition of TEL	96.2
plus 1.5 ml TEL per gal	99.2
plus 3.0 ml TEL per gal	8+0.01*

*Reference fuel "R" plus 0.01 ml TEL per gal.

TABLE 2

Comparison of commercial and pilot plant cracking to obtain motor gasoline—using natural catalyst

	Commercial scale	Pilot plant
Feed stock		
Gravity, deg. A.P.I.	30.5	31.7
50-per-cent point (ASTM distillation), °F	690	680
Yields on feed (per cent by volume)		
Gasoline (10-lb. Reid vapor pressure)	42.0	45.0
Excess butane	7.5	4.7
Gasoline (100 per cent C_4)	49.5	49.7
Gas oil	50.0	50.0
Dry gas, per cent by weight	6.2	5.0
Carbon, per cent by weight	2.8	2.8
Motor gasoline properties		
Gravity, deg. A.P.I.	60.3	60.4
ASTM distillation:		
Initial boiling point, °F	101	95
Per cent over at:		
122 °F	5.5	6.0
158 °F	22.5	24.0
212 °F	45.0	46.0
257 °F	64.0	61.5
356 °F	92.5	90.0
End point, °F	385	400
Color	+20	+20
Aniline point, °F	85	87
Sulphur, per cent by weight	0.03	0.04
Bromine No.	93	75
Octane No.:		
ASTM: with no addition of TEL	79.2	79.7
CFR-R (1939): with no addition of TEL	92.9	92.0
plus 1.5 ml TEL per gal	97.3	97.0

In general construction, fluid catalytic cracking plants do not differ a great deal from conventional low-pressure refinery equipment. Carbon steel has been used for the most part in the plants, and most of the equipment is of conventional type. Moreover, the plants are characterized by the absence of timing devices and mechanical equipment for circulating the large quantities of catalyst. No unusual equipment has been designed to combat erosion, because this has been controlled primarily by proper choice of velocities, streamlining, and use of protective wear plates.

The newer design fluid plants differ in several major respects from that typified in Fig. 1 and, as a consequence, are simpler and more compact in design and in construction, in addition to being inherently more flexible in operating characteristics.

Operating performance of commercial plants. The basic soundness of the fluid catalyst technique as applied to the cracking of petroleum has been amply demonstrated by present commercial experience. Continuous runs of as long as five months have been achieved, and six months' maintenance requirements for the initial operations of the Baton Rouge and Bayway plants—which include minor revisions to equipment—have been found to be at the rate of 5 to 6 per cent per year of the capital investment. Normal requirements should thus be considerably below thermal cracking.

The recovery of catalyst, in general, has been satisfactory, despite periods in which high losses were experienced because of faulty mechanical conditions in the dust-collecting equipment. In 9 months of operation on the Baton Rouge unit, actual catalyst losses averaged about 0.4 lb. per bbl. of feed. This figure includes rather high losses in the starting up of the unit, which should be eliminated with future experience. On the Bayway unit overall losses during the past 4 months have shown an average of 0.26 lb. per bbl. This included one turn-around period during which higher losses are normally obtained. Losses on this unit for the past month have averaged 0.12 lb. per bbl. Minor improvements and adjustments to the catalyst-recovery equipment in all plants are being continued to achieve better efficiency, and it is expected that catalyst losses from a large commercial fluid catalyst unit ultimately will be around 0.15 lb. per bbl.

Maintenance of catalyst activity in the commercial plants has been satisfactory. Inasmuch as a continuous replacement of catalyst inventory occurs by the addition of fresh catalyst to replace losses, fluid catalyst achieves what might be termed an equilibrium activity, and no replacement of the total inventory is made periodically as with conventional fixed-bed catalyst processes. The catalyst in most of the commercial fluid units has reached this state, and its performance as regards cracking ability and product distribution has been in accordance with expectations.

The flow of fluidized solids in commercial operation has been characterized by the same smoothness and ease of control experienced in the pilot-plant development work. Erosion of equipment by the circulating catalyst has not been serious. Such erosion as has been found is being reduced progressively, and it is expected that this factor ultimately will be virtually eliminated. Repair-materials requirements for the Baton Rouge and Bayway units have been at the rate of 0.8 to 1.7 per cent per year of the capital investment.

TABLE 3

Motor gasoline production and quality from fluid catalytic cracking of gas oils

	East Texas wide cut	West Texas wide cut	West Texas heavy	Coastal wide cut
Feed properties				
Gravity, deg. A.P.I.	31.7	27.3	22.3	22.1
Aniline point, °F	180	169	171	180
Sulphur, per cent by weight	0.48	1.80	2.49	0.63
Product yields (per cent by volume)				
Motor gasoline*	45.0	43.2	46.0	46.2
Excess butane	4.3	3.0	2.0	4.0
Gasoline (100 per cent C_4)	49.3	46.2	48.0	50.2
Cracked gas oil	51.2	51.2	51.2	51.2
Dry gas, per cent by weight	4.3	6.3	5.6	5.4
Carbon deposit, per cent by weight	3.1	4.1	3.4	2.6
Motor gasoline† properties				
Gravity, deg. A.P.I.	60.5	58.2	58.2	57.0
Reid vapor pressure, lb	10.0	10.0	10.0	10.0
ASTM distillation:				
Per cent distilled at:				
158 °F	25.5	18.5	18.5	23.0
212 °F	57.0	42.0	38.0	43.5
End point, °F	406	400	401	406
Recovery, per cent	97.5	97.5	97.5	97.0
Aniline point, °F	85	76	82	71
Sulphur, per cent by weight	0.03	0.18	0.246	0.044
Acid heat, °F	159	162	186	180
Breakdown, hr	9	14.5	13	10
Octane No.:				
CFR-M‡: without addition of TEL‡	80.5	79.4	77.9	80.5
plus 1.5 ml TEL per gal	84.6	83.0	81.2	84.7
CFR-R (1939): without addition of TEL	92.0	91.9	91.3	94.3
plus 1.5 ml. TEL per gal	97.0	95.9	95.3	98.1
Cracked gas oil properties†				
Gravity, deg. A.P.I.	30.0	23.6	22.7	22.0
50-per-cent point (ASTM distillation), °F	572	605	605	563
Aniline point, °F	144	129	124	96

*Reid vapor pressure, 10 lb.; end point, 400 °F.
†Inspections on product as produced without further treatment.
‡Tetraethyl lead.
‖Motor method.

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Motor-fuel operation. Catalytic cracking for motor-gasoline production normally is carried out by contacting light- or heavy-crude fractions with catalysts at moderate temperatures in single-pass operations. Commercial fluid operations for motor fuel to date have been limited to brief periods with the purpose of establishing operability of equipment before proceeding with regular war-products operations with synthetic catalyst. The initial period of operation at the first Baton Rouge plant, however, was of sufficient length to establish the yields and quality of products on a large-scale production basis.

The wide-cut paraffinic gas oil processed in the Baton Rouge plant during this period resulted in the product distributions as indicated in Fig. 2. Cracking temperatures and depth of cracking, both of which were varied over relatively wide ranges, have an effect on the yields of various components. With a given temperature, motor-gasoline (100 per cent C_4) yields ranging from 43 to 53 per cent were obtained depending on the level at which conversion was maintained; dry-gas and carbon production increased simultaneously, at the expense of yield of the heavier products. Cracking at higher temperatures resulted in a decrease in motor-fuel production, with a corresponding increase in dry gas, for a given conversion of gas oil feed.

Quality characteristics of the motor fuels and heating oils which correspond to the yields presented are summarized in Fig. 3. Anti-knock quality of the motor-fuel products (with no addition of TEL and with a Reid vapor pressure of 10 lb.) obtained from cracking operations at moderate temperature with the paraffinic gas oil showed a CFR-R octane number of approximately 92, regardless of conversion level. Operations at high temperature, however, resulted in a higher quality product, viz., one with a CFR-R octane number of approximately 94—presumably because of the larger amount of olefins in the naphthas thus produced. The addition of 3 ml per gal of TEL to 2 typical motor gasolines of 10 lb. Reid vapor pressure improved anti-knock quality to CFR-R octane numbers of 98.5 and 99.5, as follows:

Type of catalyst	Natural	
Cracking temperature	Moderate	High
Gas-oil conversion, per cent	54	61
ASTM octane No. (no addition of TEL)	79.8	80.7
CFR-R octane No.:		
Without addition of TEL	92.4	95.7
Plus 1.5 ml. TEL per gal	97.0	98.0
Plus 3.0 ml. TEL per gal	98.5	99.5

Increasing operations with synthetic catalyst, motor naphthas of higher than 100 CFR-R octane number (with 3 ml TEL per gal.) have been produced in commercial fluid operations from both paraffinic- and naphthenic-type feed stocks. Typical results on a light paraffinic gas oil are shown in Table 1. It is evident that high quality motor fuels can be produced by fluid catalyst cracking.

The volatility of the motor fuels produced with cracking of the paraffinic gas oil increased with conversion levels, as did the A.P.I. gravity. Stability of the fluid catalytic naphthas was good, and no finishing treatment was required aside from a light cautic wash and the addition of an inhibitor. The heating-oil-fraction properties also vary with conversion—a somewhat lower A.P.I. gravity and a lower boiling stock resulting as conversion increases. The stock as produced is of excellent sta-

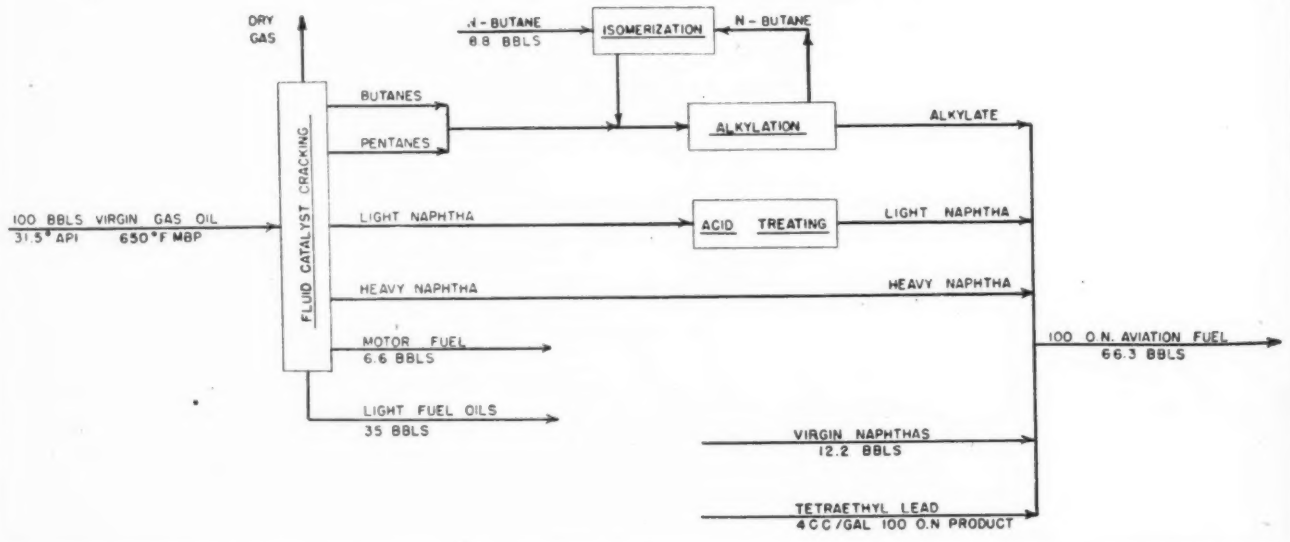
TABLE 4

Typical product quality of catalytic aviation base stocks—commercial operations—synthetic catalyst

Type of operation	Paraffinic feed stocks				Naphthenic feed		
	Single-stage			Two-stage	Single-stage		
Temperature level	Low	High	Hydro-genation	High	Low	High	High
Feed stock (gravity, deg. A.P.I.)	36.7	36.1	36.1	30.5	33.8	29.6	29.6
Gas oil conversion, per cent	52.7	64.0	64.0	60.0	56.6	63.5	81.3
Aviation gasoline							
Reid vapor pressure, lb	7.0	7.0	6.8	7.0	7.0	6.9	6.9
Gravity, deg. A.P.I.	61.5	56.4	58.2	57.8	57.7	55.8	51.3
Aniline point, °F	92	45	84	69	75	34 †	24 †
Acid heat, °F	56	135	6	36	44	144 †	100 †
Bromine No., centigrams per gram	22	64	0	12	22	45 †	22 †
Sulphur, per cent by weight	0.02	0.03	....	0.03	0.03	0.03†	0.03†
ASTM distillation:							
Per cent by volume over at:							
167 °F	33.5	34.5	28.5	31.0	29.0	28.5	24.0
221 °F	61.0	56.5	54.0	55.0	53.0	55.5	46.5
275 °F	84.5	80.0	81.5	77.0	77.5	85.0	75.0
293 °F	91.0	90.0	91.0	90.0	88.5	92.7	91.4
End point, °F	332	322	318	318	326	319	320
Octane No.:							
ASTM: without addition of TEL	81.0	82.7	80.4	83.2	81.5	81.7 †	86.0 †
AFD-1C: plus 4 ml. TEL per gal	93.3	91.7	98.2	96.5	94.9	92.6 ‡	97.4 ‡

*Shows high-temperature gasoline from column 2 after hydrogenation.
†Inspected on pentane-free basis.
‡Rated with pentanes added for 7-lb. Reid vapor pressure.

Fig. 4. Aviation gasoline by fluid catalyst cracking



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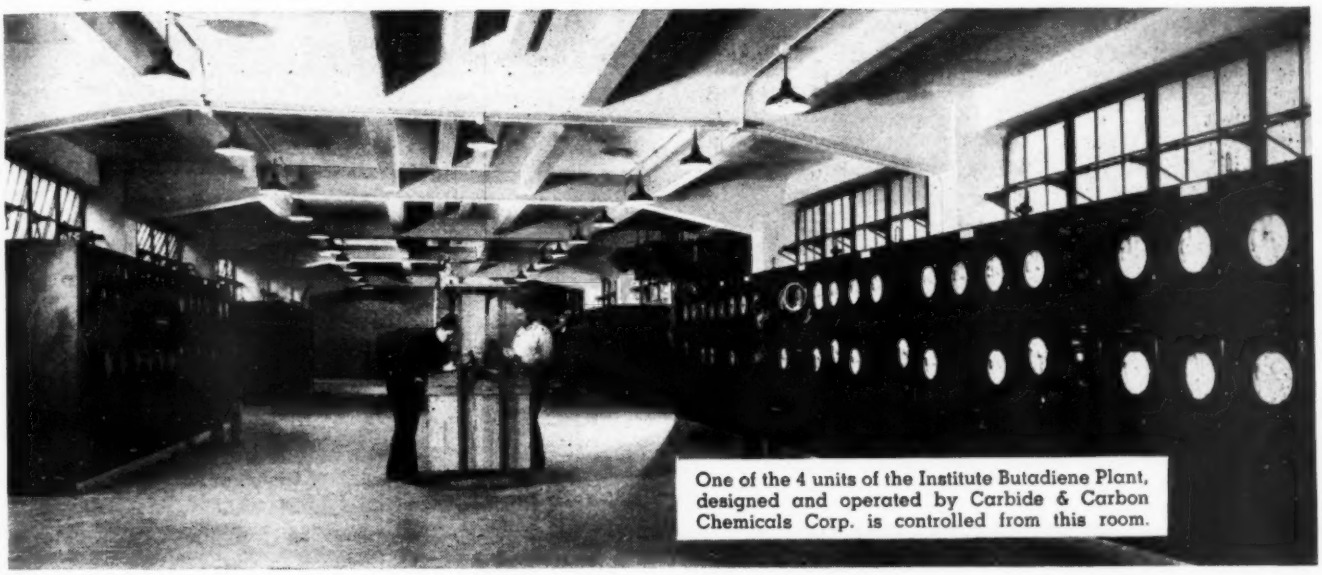

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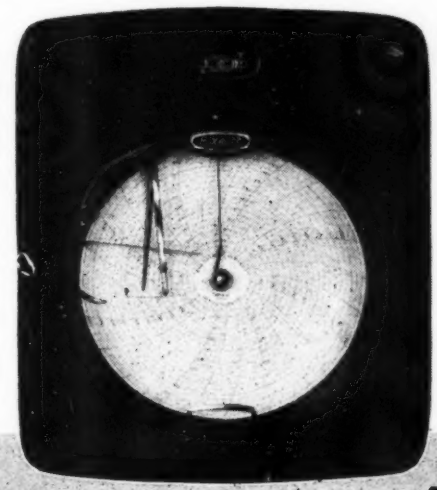

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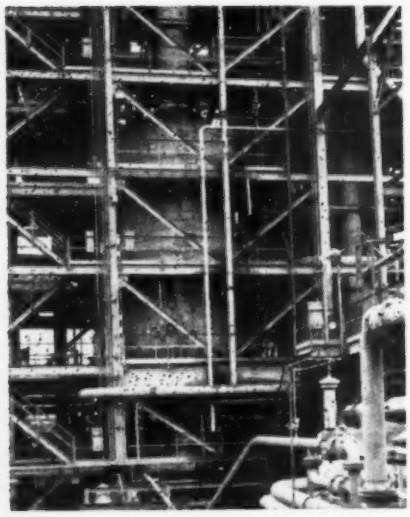

Fig. 5. Reaction vessel in fluid catalyst cracking plant, in which oil and catalyst are contacted

bility. Pour point of the heating oil as produced from the unit ranged from — 10 to + 10°F.

Plant throughput, during the period for which results have been presented, exceeded nominal design capacity by a substantial margin. As is indicated in Table 2, commercial yields, product quality, and operating conditions were in good agreement with those obtained in the semi-commercial 100-bbl.-per-day pilot plant. Typical pilot-plant results on 3 feed stocks are presented in Table 3.

Although it has been demonstrated that the cracking of virgin gas oil to gasoline and other products in commercial operations can be carried out over a wide range of temperatures and conversion levels, the choice of the specific level to obtain optimum operations is dependent largely upon such economic considerations as the relative demand of heating oils and gasoline, availability of quantity and type of feed stocks, price structure, etc. With normal prewar demands for furnace oils, a yield of about 45 per cent of 10-lb. Reid vapor pressure motor gasoline was generally favored. However, with increased emphasis on maximizing motor-fuel production from raw material, it may become desirable to process further the gas oil unconverted in single-stage catalytic cracking. Experimental fluid cracking of virgin stocks, with internal recycling of the catalytic gas oil, for example, has yielded as high as 80 per cent of motor gasoline (100 per cent C_4) based on fresh feed. However, cracking of the cracked gas oil also can be accomplished thermally to yield 40 to 50 per cent motor fuel based on the feed to the thermal operation—the yield depending on the characteristics of the cracked gas oil.

Catalytically-cracked gas oils are rather refractory toward further cracking, and tend to produce larger amounts of carbon and dry gas than virgin gas oils—thus resulting in reduced yields if operations proceed to ultimate gasoline yield. It has been found, however, that the undesirable constituents in the cracked gas oil can be eliminated by hydrogenation, with little or no gasoline formation and, consequently, with low hydrogen consumption, to produce a gas oil which is in most cases superior to virgin stocks in cracking quality. On the basis of experimental yields obtained from cracking and hydrogenation operations, it has been calculated that single-stage catalytic cracking, followed by ultimate-yield thermal processing of the cracked gas oil, would compare as follows with an ultimate-yield operation in which the cracked gas oil is lightly hydrogenated and then returned to catalytic cracking:

	Catalytic plus thermal cracking	Catalytic cracking plus hydrogenation
Yield on virgin feed (per cent by volume)		
Gasoline (10-lb. Reid vapor pressure)	63	92
Excess butane	5	13
Gasoline (100 per cent C_4)	68	105
Tar (12 deg. A.P.I.)	30	..
ASTM octane No.	75	82

It will be noted that a large increase in yield on original gas oil in indicated through use of hydrogenation. Moreover, higher octane-number gasoline is produced, inasmuch as substantially all of the gasoline is of catalytic origin. Utilization of this technique should be of growing interest as petroleum reserves become more limited.

War-products operation. All commercial fluid plants now in operation are engaged in the production of war products. The fundamental difference between motor and war-products operation lies in the catalysts which govern the cracking reaction. The catalyst now in use in fluid plants producing war materials is a synthetic material which is particularly applicable to this type of operation. Due to the rôle that these operations are playing in supplying the nation's current military needs, only a general discussion of types of operation and qualities of products can be made at this time.

In cracking with synthetic catalyst, as with any other type, product distribution and naphtha composition are affected to a large extent by the type of feed stock charged, and by the temperature and depth of conversion at which cracking is carried out. The general effect of these variables when gas oils are processed is summarized as follows:

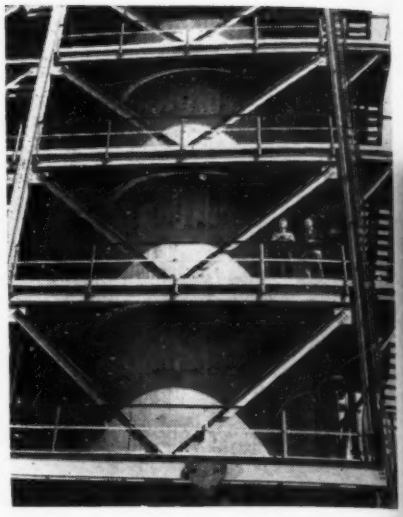

Fig. 6. Fluid catalyst regeneration vessel in which carbon is continuously burned from spent cracking catalyst

a. *Temperature:* Formation of saturated paraffins at a given conversion is favored by low temperatures. Aviation gasolines produced at the lower temperature levels are characteristically high in saturated isoparaffin content, but are low in aromatic concentration. High-temperature operations, on the other hand, lead to more highly unsaturated and, particularly, more aromatic fuels. Unsaturation in the butane and pentane fractions is affected similarly.

b. *Conversion:* Depth of cracking affects both yield and composition to a major degree. The higher conversions, at a given temperature, yield more highly aromatic and more saturated fuels.

c. *Feed stock:* Naphthenic feed stocks can be cracked to satisfactory yields of aviation gasolines which are generally of higher quality than those obtained from paraffinic stocks. With a given type of stock, boiling range also affects results—the lighter and more refractory stocks generally yielding products which are more saturated. It is to be mentioned that, regardless of the cracking conditions at which a naphtha is produced, further catalytic processing of this naphtha in subsequent and separate operations will result in further improvement in aviation-gasoline quality, largely through the elimination of olefinic compounds.

In applying catalytic cracking to the production of war products, therefore, optimum type of operations are determinded by consideration of combined refinery operations, inasmuch as, for example, the production of raw materials for alkylation is of equal importance to the production of aviation-base stock itself. The flexibility of the fluid catalyst process permits choice of cracking operations over wide ranges of temperature, conversion, and feed stocks;

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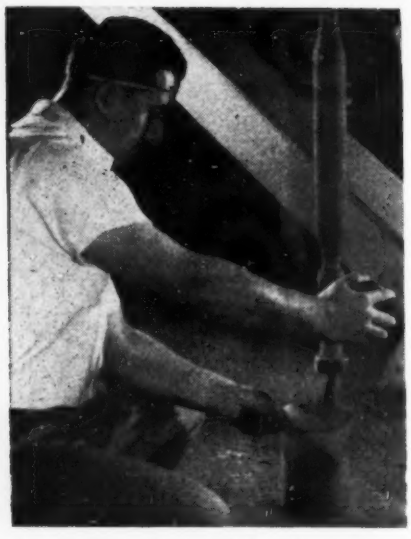

Fig. 7. Operator withdrawing sample of fluid catalyst from commercial plant

and thus the operations which are most suitable to a particular refinery situation can be applied readily. With current aviation-fuel specifications and demands, single-pass high-temperature operations at moderate conversions appear optimum from a standpoint of utilizing most efficiently a given cracking capacity when cracking paraffinic-type stocks.

Characteristics of typical aviation-gasoline-base stocks produced over a rather wide range of conditions in commercial units are given in Table 4. It will be noted that the higher temperatures of operation give, before further treatment, a total aviation cut having somewhat poorer AFD*-1C anti-knock quality than that produced in low-temperature cracking. This is due primarily to the more highly olefinic nature of the high-temperature stocks—which, however, are more aromatic. It is pertinent that the olefins in the catalytic naphthas are concentrated largely in the fraction boiling up to 225°F. In practice, therefore, this fraction generally is treated to remove olefins, whereby a superior-quality fuel is produced, or is discarded to motor fuel and replaced by natural naphtha while the heavy highly aromatic naphtha in the 225 to 350°F. boiling range is blended directly into aviation naphtha. The production of raw materials for alkylation is considerably higher in high-temperature cracking; and, when overall aviation production is under consideration, cracking at these conditions is definitely superior to that at low levels.

Elimination of the olefinic constituents of the naphthas produced at high temperature to improve AFD-1C anti-knock quality may be accomplished in a number of ways. Two methods which have been utilized commercially are hydrogenation and catalytic treating. Results obtained from such processing are shown in Table 4, and it is apparent that final products of high anti-knock quality (96.5-98.0 AFD-1C) result. Another method is the application of severe acid treating, whereby comparable improvements may be obtained through removal of olefins by polymerization. Spent alkylation acid has been found to be suitable for this treatment. Inasmuch as most of the integrated aviation-gasoline operations use alkylation, the application of acid treating is of considerable interest.

Naphthenic stocks yield, in general, better quality aviation-base stocks than paraffinic feeds at comparable cracking conditions. Table 4 illustrates that extremely high quality stocks can be produced when cracking proceeds at severe once-through conditions. Severe operations of this nature produce increased quantities of aromatics in the aviation-gasoline boiling range, and reduce at the same time the olefins which reduce AFD-1C anti-knock quality.

Application of fluid cracking for aviation-gasoline production in combination with other refinery operations. To evaluate properly catalytic cracking operations for production of aviation fuel, the process must be considered in combination with other refinery processes, particularly alkylation; because, in a broad sense, catalytic cracking is essentially a source of alkylate as well as of premium aviation-base material.

One application of fluid catalytic cracking in integrated refinery operations for aviation-fuel production is outlined in Fig. 4. This illustration is based on processing a typical heavy-paraffinic gas oil at high temperature; the butylenes and amylenes produced are alkylated with isobutane, and the light catalytic naphtha is severely acid-treated with sulphuric acid to improve AFD-1C anti-knock quality by removing the olefins therein. The catalytic heavy-aromatic fraction, which is high in anti-knock quality as produced, is blended directly into the final gasoline. The blend of alkylate and naphthas from the catalytic operation is substantially higher in octane number than specifications require, and readily available virgin naphthas, which are of comparatively low quality, are blended in such quantity that the final blend will meet specifications—thereby increasing the volume of specification aviation product. In this scheme of operations, some isobutane is necessary to supplement the isobutane produced in catalytic cracking which supplies a quantity that is roughly sufficient to alkylate only the butylenes. Normal butane, which is generally available, is isomerized readily to isobutane in relatively simple and inexpensive equipment.

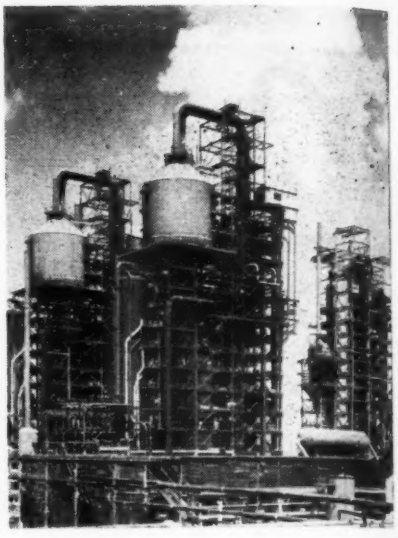

Fig. 8. General view of three fluid catalyst cracking units

(Unit at right is pioneer catalyst plant. Two units at left, of new and simplified design, are now in operation)

The yield of aviation gasoline resulting from the combination of processes discussed (Fig. 4) is quite high. For every 100 bbl. of heavy paraffinic gas oil charged to the fluid catalyst unit, it is possible to produce 66.3 bbl. of 100-octane-number aviation fuel meeting present specifications. Of this quantity, 12.2 bbl. are virgin-naphtha fractions which can be carried in the blend. A substantially higher yield of aviation gasoline can be obtained by hydrogenating, rather than acid-treating, the light catalytic naphtha. Production of specification aviation fuel from such a scheme of operation is indicated to be 78.4 bbl. per 100 bbl. of paraffinic virgin gas oil charged to cracking.

With the completion of the present construction program, the fluid catalyst process will be the major cracking process for producing 100-octane aviation gasoline. On resumption of normal economic conditions after the war, the fluid process will provide a means of converting the heavier petroleum fractions with maximum efficiency and economy into premium motor fuels.

Acknowledgment. The fluid catalyst process represents a contribution of the Standard Oil Development Company to a cooperative study on catalytic refining participated in by the refining organizations of Standard Oil Company of New Jersey, and by Anglo-Iranian Oil Company, Ltd., M. W. Kellogg Company, Shell Oil Company, Inc., Standard Oil Company (Indiana), The Texas Company, and Universal Oil Products Company.

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*Aviation Fuels Division.

Extraction of Aromatics From Hydrocarbon Mixtures*

By ALLEN S. SMITH and J. E. FUNK
Blaw-Knox Division, Blaw-Knox Company

THE demand for toluene increased from a prewar annual production of approximately 25,000,000 gal. to several hundred million gal. in 1942. More recently the requirements for higher aromatics have increased as their particular value in aviation fuel has become recognized. A large part of new production is being derived from petroleum. This was a source of toluene as early as 1880 in Russia. Borneo crudes containing 40 per cent aromatics supplied England with toluene in 1914. The first plant cracking operation produced some toluene in the United States in 1917. Since that time progress made in the chemistry of petroleum and in knowledge of unit operations enabled the huge demands of 1940-43 to be met without delay.

Petroleum as a source of aromatics presents two problems: First, production and, second, recovery. Progress in production has been greater than that in recovery because no great demand has previously arisen for pure components. The work sponsored by the American Petroleum Institute has demonstrated the complexity of petroleum and the difficulty of resolution of its components.

The existence of azeotropes and the abnormally low relative volatility of aromatics in non-aromatic mixtures limits the effectiveness of fractional distillation in separating aromatics. The presence of azeotropic mixtures of hydrocarbons has been difficult to establish. Young[18] reported an azeotrope of *n*-heptane and methylcyclohexene. This was refuted by Bromiley and Quiggle.[2] Bouzat and Schmitt[1] and later Scatchard, Wood, and Mochel[15] gave data on an azeotrope of benzene and cyclohexane. Mizuta[11] reported azeotropes of benzene and toluene with gasoline fractions. Tongberg and Johnston[16] did not find an azeotrope of n-hexane and benzene although Griswold and Ludwig[6] believe that one exists. The latter authors also demonstrated the existence of a benzene azeotrope with methylcyclopentane.

Since research and practice have demonstrated the difficulty of aromatic separation by distillation, other methods have been used. Azeotropic distillation with a third type component,[9] solvent extraction, extractive distillation[4] and combined azeotropic and extractive distillation[3] have been applied. An extractive distillation process was used in the first commercial unit to produce toluene from petroleum during the present war, and it is apparently widely used.[13] These methods enable aromatics to be separated from other hyrocarbons by reason of the effect of structural differences. Such differences oppose separation by distillation, and result in azeotrope formation between hydrocarbons having nearly equal vapor pressures. The methods involving extraction are more generally useful than azeotropic distillation because they can be applied to aromatics in hydrocarbon mixtures of wide boiling range.

Solvent extraction of complex mixtures, such as hydrocarbon and vegetable oils, has been carried out commercially for many years. The object is to obtain a product which has properties more desirable for a particular application than those of the feed material. The results of extraction have been evaluated in terms of physical properties. Consideration of the methods used and of the limited data indicate that relatively simple separations are made. Since little is known concerning the actual distribution of the components between the products of extraction or of their distribution coefficients, solubility and equilibrium data must be obtained for each feed material to evaluate the practicability of a solvent and the results for a given extraction procedure.

The extraction of components in a pure state from a complex mixture requires a knowledge of the solubility and distribution characteristics of the component types making up the mixture. With sufficient data it should be possible to design equipment to separate according to type in a manner analogous to separation by relative volatilities in distillation. This method of approach was used in the work to be described in determining the relative distribution of components, particularly aromatics, in solvent extraction of hydrocarbon mixtures. The complexity of such mixtures and difficulties in analysis limited the number of component types which were studied.

Selection of solvent. Single solvents commonly used in lubricating oil extraction are unsuitable for the separation of pure components. To accomplish complete separation, at least theoretically, a solvent must be partially miscible with the component types to be separated at the operating temperature. Miscibility cannot be too limited or solvent requirements become prohibitive. Solvents partially miscible with aromatics as well as paraffins in the gasoline boiling range, and having other desirable characteristics of a practicable solvent are not common. For this reason mixed solvents have been used. A German patent[5] discloses the use of mixtures of ethylene, diethylene, or propylene glycols, which are relatively insoluble in all components, with sulphur dioxide at minus 10° C. A Japanese patent[7] claims the use of water with methanol or ethanol. Ethylene glycol has been used with acetone and methanol.[17] Many other mixtures of solvents have been proposed.

Ethylene glycol mixtures with methanol and with dipropylene glycol were used in the present work. Toluene was the first aromatic compound considered. Solubility diagrams were obtained at 77° F. for ternary systems made up of the mixed solvents and toluene, of the mixed solvents with a commercial paraffinic naphtha and with mixtures of the naphtha and toluene. The solubility of the naphtha was determined to be less than that of toluene, and that of their mixtures intermediate between

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Fig. 1. Solubility diagrams at 77°F. System: methyl alcohol-ethylene glycol-hydrocarbons

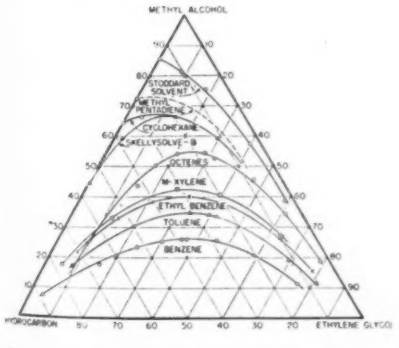
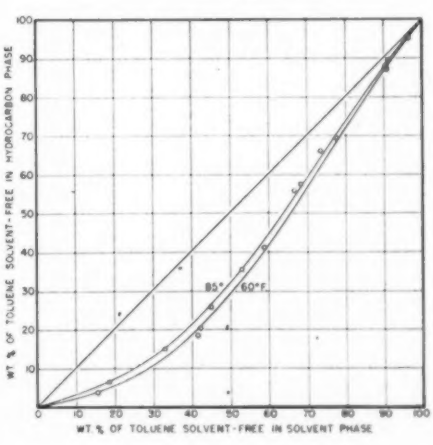


Fig. 2. Equilibrium diagram. System: toluene-Skellysolve B-70 methanol + 30 glycol



the solubility of the two pure component types. Solubilities of other aromatic compounds, cyclohexane, mixed octenes and methyl pentadiene in two solvent mixtures were also measured. Some of these data are shown in Fig. 1 for the hydrocarbons, methyl alcohol and ethylene glycol.

Fig. 1 indicates that solubility depends upon molecular weight as well as chemical type of the components. In the same boiling range non-aromatic compounds are less soluble than the corresponding aromatic. If relative solubility is a measure of the distribution coefficients then it is possible to effect a separation of the components by solvent extraction from a close cut hydrocarbon mixture. However, in a wide cut, such as a gasoline, various types of components of different molecular weights might have overlapping solubilities. Separation would then be expected to be impossible.

It was thought expedient to investigate the continuous extraction of relatively simple mixtures to establish the utility of mixed solvents, and of whole gasolines to determine the importance of the molecular weight effect. This would eliminate the necessity for fundamental work with a large series of compounds, most of which would not be readily obtainable. Solubility and equilibrium measurements, were, therefore, made on mixtures of an aromatic and a naphtha with a binary solvent of constant composition to obtain data for approximate extraction calculations. The compositions used were methyl alcohol and ethylene glycol in the ratios 70/30 and 55/45, and dipropylene glycol in the ratio 65/35 by weight. These ratios were chosen to give partial miscibility at 77° F. with benzene.

Characteristics of the mixed solvents. An equilibrium diagram is shown in Fig. 2, and a solubility diagram in Fig. 3 for a solvent composed of 70 per cent methanol and 30 per cent ethylene glycol. The diagrams were obtained by separating mixtures of solvent, toluene, and Skellysolve *B* at equilibrium, determining the solvent composition of each phase and the aromatic content of the solvent-free phases. The curves are characteristic of systems in which the two components to be separated are both partly miscible with the solvent. The use of two coordinates to represent this system is not strictly correct since five components are present (Skellysolve B contains naphthenes as well as paraffins). There is a distribution of the solvents between the two phases as well as a distribution of the hydrocarbons. This is indicated by the fact that the solubility of a hydrocarbon mixture in the solvent is not the same as the solvent content of the extract phase separated at equilibrium, which contains the same hydrocarbon mixtures. Fortunately, since the solvent content of the raffinate is small no large change in solvent composition can be possible. It was found that Skellysolve *B* did not change in composition in single equilibrium separations. Therefore, the assumption of a ternary mixture is justified as a first approximation, and the design calculations for countercurrent extraction are simplified.

TABLE I

Extraction data for synthetic hydrocarbon mixtures

Countercurrent extraction without reflux in 12.5 ft. column

System	1	2
Temperature, °F.	75	85–90
Flow rates based on column area, lb. per sq. ft. hr.:		
Solvent	250	527
Hydrocarbon	107	91
Per cent aromatic in—		
Feed	49.5	23.5
Raffinate	.05	8.2
Extract	62.5	60.5
Equilibrium with feed, calculated	62.5	58.
Solvent content, lb. solvent per lb. hydrocarbons:		
Of extract	2.15	16.7
At equilibrium, calculated	2.3	12.5

These conclusions were confirmed by data obtained with the following systems: toluene-Skellysolve B-methanol + ethylene glycol in the ratio 55/45; toluene-Stoddard solvent-, and *m*-xylene-Stoddard solvent-methanol + ethylene glycol in the ratio 70/30; toluene-Skellysolve *B*-, and *m*-xylene-250-350° F. paraffinic cut-dipropylene glycol + ethylene glycol in the ratio 65/35.

The applicability of the solvents was further checked by continuous countercurrent extractions in a 1-in. glass column packed with 12.5 ft. of ¼-in. Berl saddles. Runs were made with (1) toluene-Skellysolve *B*-methanol + ethylene glycol in the ratio 70/30; and with (2) xylene-250-350° F. paraffinic cut-dipropylene glycol + ethylene glycol in the ratio 65/35. Operating conditions were estimated from the appropriate equilibrium and solubility data by the method described by Randall and Longtin.[14] Results for two runs with solvent as the continuous phase are given in Table 1.

The runs of Table I were made with a solvent to feed ratio only slightly greater than that calculated to be minimum. Therefore, the extract could closely approach equilibrium with the feed. Actual and estimated results agree well for system 1. In system 2 the aromatic concentration and solvent content of the extract are greater than corresponds to conditions at equilibrium with the feed. This effect can be due, in part, to a distribution of naphthenes as well as of aromatics between the phases in multiple contact extraction. The equilibrium diagram determined with the 250-350° F. paraffinic cut and xylene is correct only for the naphthene/paraffinic ratio in that cut. A new equilibrium diagram would be required to correctly represent the system at the extract end of the column. The actual change in naphthene/paraffin ratio was from 1.2 in the feed to 3.5 in the extract.

Other runs made with reflux, and in a 6-ft. section of the column indicated that the stripping section of a column to separate aromatics from non-aromatics could be safely designed on the basis of the equilibrium and solubility data as obtained. The rectifying section, however, should be designed on the basis of data for the most soluble non-aromatic in order to separate non-aromatics from aromatics.

In this preliminary work to demonstrate the utility of mixed solvents by extraction of simple hydrocarbon mixtures, the selectivity of the solvent mixtures for chemical type was verified. The importance of molecular weight was investigated by extraction of whole

Fig. 3. Solvent content of phases separated at equilibrium. System: toluene-Skellysolve B-70 methanol + 30 glycol

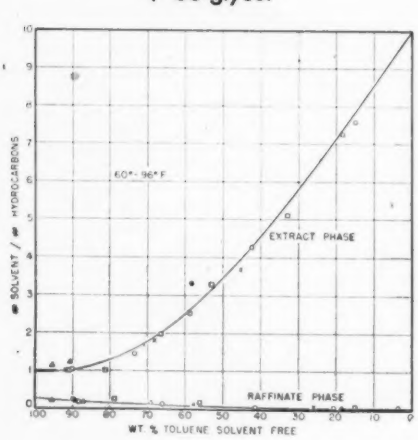
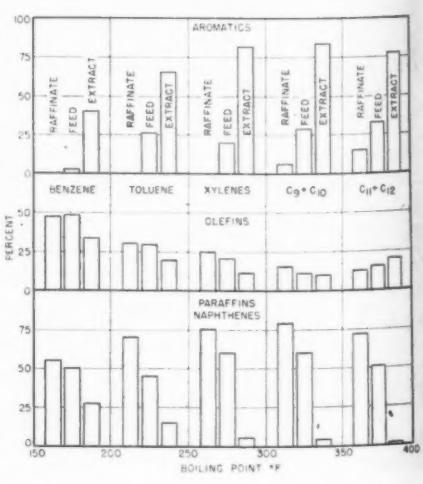
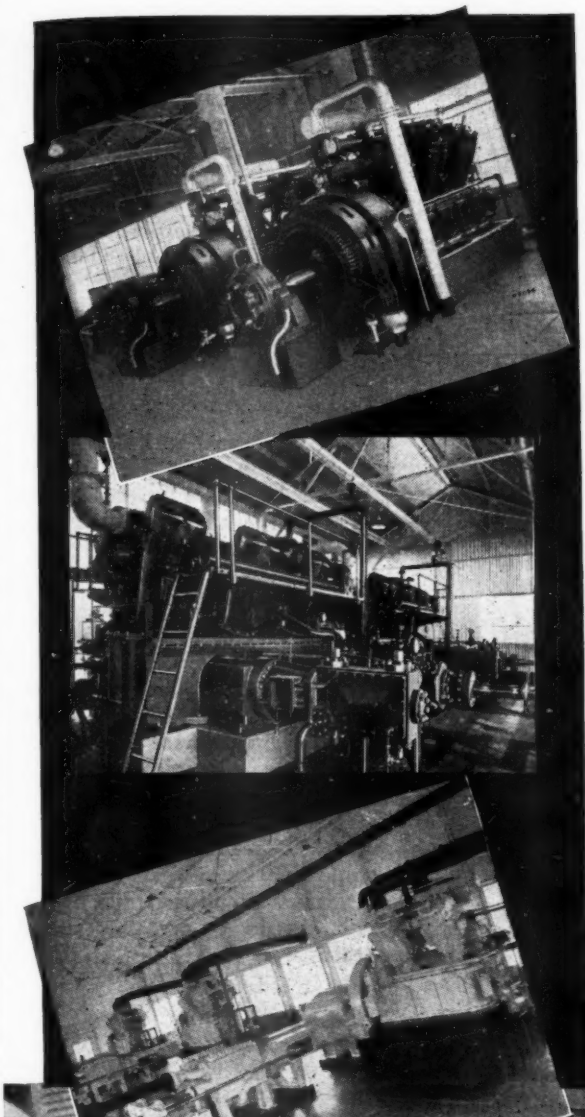


Fig. 4. Extraction of sample 1 with 70 methanol + 30 glycol. Composition of feed and products





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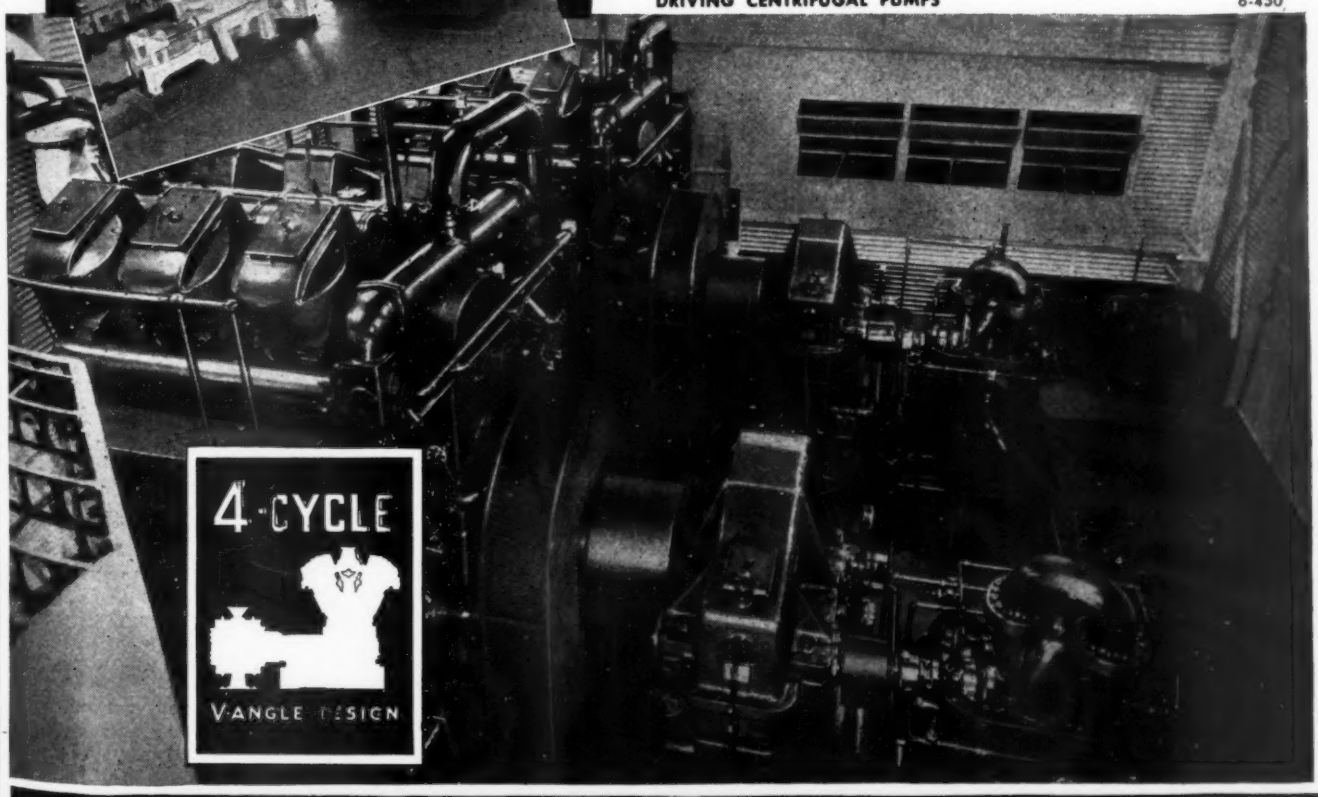


gasolines in a 42-ft. column designed with consideration of the greater solubility of non-aromatics other than paraffins, but not with additional experimental solubility or equilibrium data.

Description of the extraction column. Information derived from the preceding runs in the 12.5-ft. column was used for an approximate design of a column for extraction of gasoline.

Reflux. Extract reflux is essential to obtain an extract product having an aromatic concentration greater than that in equilibrium with the feed. Raffinate reflux has no appreciable effect on the stripping operation.

Number of extraction stages required. This will vary with the system, and with the aromatic concentration of the feed. Assuming a 20 per cent toluene feed, an 85 per cent extract and a 1 per cent raffinate, 14 stages are necessary at 2 times minimum reflux in the toluene-Skellysolve B-70 methanol + 30 ethylene glycol system. Of these, 7.5 units are below the feed and 6.5 above the feed. A total of 8 units, equally divided, are needed under the same conditions if the solvent is 65 dipropylene glycol + 35 ethylene glycol. The graphical method of Randall and Longtin,[14] as applied by Maloney and Schubert,[10] was used in calculation.

H.E.T.P. No runs were made specifically to obtain this value. A maximum *H.E.T.P.* of 2 ft., within the probable limits of 1⅓ to 2 ft., and a maximum overall *H.T.U.* based on the solvent phase of 3 ft., within the limits 2 to 3 ft., were computed for rectification in the xylene-mixed glycol system. These values are in the range reported by Ney and Lochte[12] for ¼-in. Berl saddles in a 21-mm. column using the

TABLE 2
Description of column feeds

Sample No.	Type	Added component	90 per cent boiling range, °F.
Solvent: 70 per cent methanol+30 per cent ethylene glycol			
1	Vapor phase cracked gasoline	None	105–420
2	Cut from sample 1	Toluene	160–275
3	Vapor phase cracked aromatic distillate	None	170–350
Solvent: 65 per cent dipropylene glycol+35 per cent ethylene glycol			
4	Cut from sample 1	Xylene	228–350
5	Blended cuts from paraffinic naphthas	Xylene	250–350

system acetic acid-water-methyl isobutyl ketone. Flow rates based on column cross section were 756 and 82 lb. per (sq. ft.) (hr.) for the solvent and hydrocarbon phases respectively. The solvent phase was continuous.

Flooding rates. Specific gravity differences vary with the systems. Differences are in the range 0.166 to 0.278 at the raffinate end of the column and 0.024 to 0.159 at the extract end. In a column of uniform cross-section, conditions at the extract end will limit flow rates. Incipient flooding was observed in the mixed glycol system at flows of 945 and 182 lb. per (sq. ft.) (hr.) for the solvent phase of sp. gr. 1.015 and raffinate phase of sp. gr. 0.852, respectively. The raffinate phase was dispersed.

Choice of dispersed phase. It is commonly accepted that the phase of greater volume, the solvent in this work, should be dispersed. The porcelain packing is wet by the solvent phase, which does not break into discrete particles. A slight improvement in separation was noted when the hydrocarbon phase was continuous; it was more noticeable in rectification than in stripping. However, irregularities in operation cause a greater lag in the attainment of a steady state when the hydrocarbon is continuous. For this reason, the hydrocarbon was usually dispersed.

Column details. The column was constructed of 42 ft. of 1-in. pipe of which 38.5 ft. were packed with ¼-in. Berl saddles; 18-in. settling sections were left at either end. Sight glasses were provided at top and bottom so that either the solvent or hydrocarbon phase could be made continuous. Since it had been observed that adequate stripping had been obtained in as little as 6 ft. of column, and rectification was of particular interest, only ¼ of the column was intended for stripping. Sample points located at 2½-ft. intervals were available as alternate feed inlets.

Feed, solvent, and reflux were introduced into the column by proportioning pumps from reservoirs placed on balances. The heavy phase was at first taken from the column through a conventional type of inverted U-loop. Slight variations in the rate of discharge due to changes in interfacial level in the column upset operation seriously. The loop was abandoned and a solenoid valve was used to control the rate of discharge of the heavy phase. The valve was operated by an electronic relay actuated by a contact made between two electrodes placed in the sight glass. The relay operated only when the solvent phase shorted both electrodes. Interfacial level was maintained within ±¼ in., and a steady state of extraction was obtained.

Solvent recovery. Since a solvent must be more polar than the hydrocarbons, it is to be expected that hydrocarbon-solvent azeotropes can exist and will influence the method of solvent recovery. For that reason, solvents are commonly selected which are water-soluble or which differ widely in boiling point from the hydrocarbons to facilitate the recovery of the solvent. Both the methanol and the glycols which were used in the present work form hydrocarbon azeotropes. To separate the solvents from the extract hydrocarbons, in order to prepare reflux, two methods were used.

The methanol-ethylene glycol solvent was separated by batch extraction of the extract with several volumes of water. About 5 per cent of the hydrocarbons present in the extract are lost by this method of separation. The dipropylene glycol-ethylene glycol solvent was removed by continuous vacuum distillation of the extract in a packed column. The column was designed

Fig. 5. Extraction of sample 2 with 70 methanol + 30 glycol. Composition of feed and products

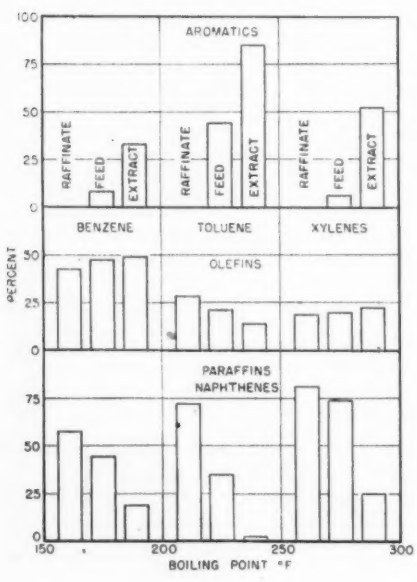
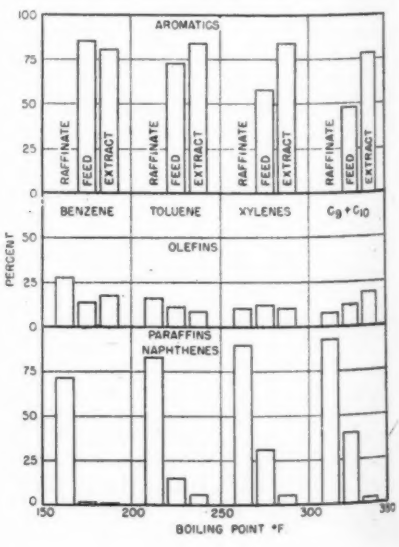


Fig. 6. Extraction of sample 3 with 70 methanol + 30 glycol. Composition of feed and products.



from equilibrium data obtained with the solvent mixture and xylene. It was constructed of 35-mm. glass tubing with a 30-in. section packed with ¼-in. steel rings. The extract entered at a point 8 in. from the top of the column. Hydrocarbons were stripped from the solvent which was reboiled and collected in a receiver under vacuum. The overhead product was composed of approximately 15 per cent ethylene glycol and 85 per cent hydrocarbons. The condensed vapor separated into two phases on cooling. One was hydrocarbons containing about 0.01 per cent glycol. This was decanted and collected as product. The other phase contained glycol, any water present in the system and about 0.02 per cent hydrocarbons. Part of this layer was refluxed to the column and part was drawn off to eliminate water from the system. Distillation was carried out at 75 mm. absolute pressure. Quantitative recovery of extract hydrocarbons could be made by this method. The recovered solvent was free from hydrocarbons and was returned to the extraction column.

Extraction of gasolines. Data on five samples extracted in the 42-ft. column are given in Table 2.

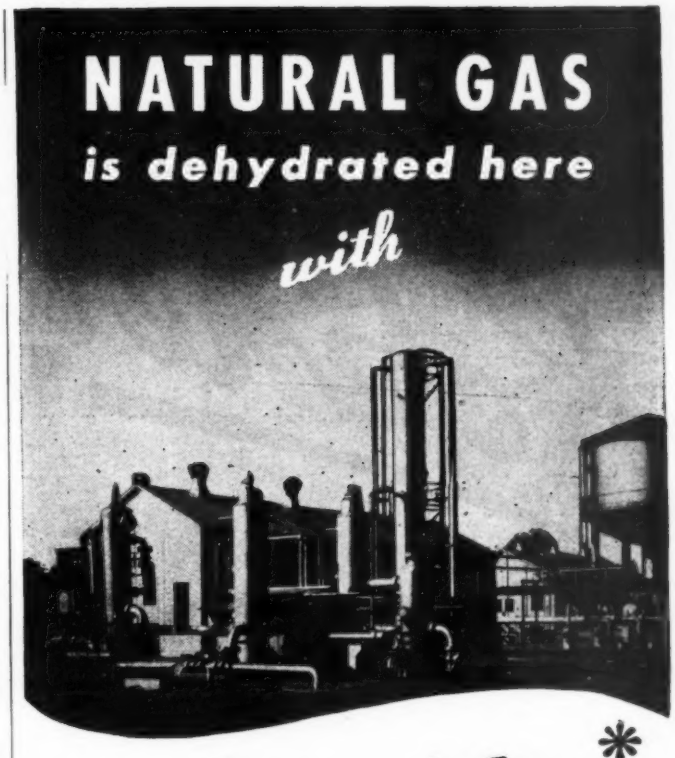
Extraction runs were continuous for periods of 24 to 72 hr. Operating conditions were set approximately by calculation from the appropriate equilibrium and solubility curves. Solvent and reflux ratios were then varied to give the lowest solvent content of the extract consistent with a low gravity of raffinate. These latter conditions are given in Table 3.

The products from samples 1-4 were fractionated. Blends were made of aromatic cuts and analyzed for aromatic content by specific dispersion, for olefins by titration and for paraffins + saturated naphthenes by sulfonation of other components. The products from sample 5 were analyzed by the refractive intercept method for paraffins, napthenes and aromatics; the latter was checked by sulfonation. The results are presented in a semi-quantitative manner because the individual analyses are not of equal accuracy. The composition of each aromatic cut from the feed and products is plotted in Figs. 4 to 8 for the five samples.

Discussion of results. An increase in specific gravity of the extract over that of the raffinate throughout the entire boiling range of the products was characteristic of all the samples. It is due in part to the greater aromatic content of the extract. Figs. 4 and 8 indicate essentially complete concentration of C_6 to C_{10} aromatics in the extract. C_{11} and C_{12} aromatics have not been concentrated in the extract as completely. This can be due to their lower solubility. The solubility of these compounds can be in the solubility range of the lower boiling non-aromatics. The plots for paraffins and naphthenes show that these compounds are more concentrated in the C_6 fractions of the extracts than in higher molecular weight cuts. Such overlapping of solubilities, inherent in a wide-boiling cut, will limit the recovery of total aromatics and the purity of the extract. The plots for olefins show a small irregular distribution between raffinate and extract, but a consistently greater distribution in the extracts of the high molecular weight cuts. It is concluded that the distribution of aromatics and non-aromatics in the range C_7 to C_{10} depends more on structure than on molecular weight.

Fig. 8 shows that there is a separation between naphthenes and paraffins. The naphthene/paraffin ratio is greater in the extract than in the feed. The degree of separation increases with the efficiency of extraction, as proved by other runs with the same sample.

The percentage of non-aromatics originally present in the whole feed, or each cut, which is found in the extract is an inverse function of the aromatic content of the feed, or of each cut. This percentage increases in the order paraffins, saturated naphthenes, and olefins. This order of separation is also shown by the relative heights of the rectangles for the raffinates and extracts representing these components in the figures.



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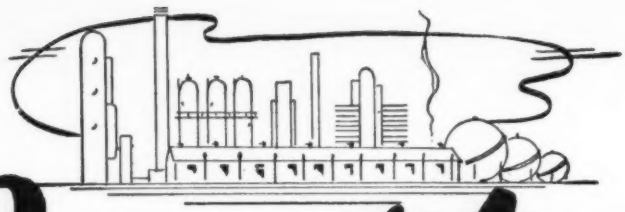

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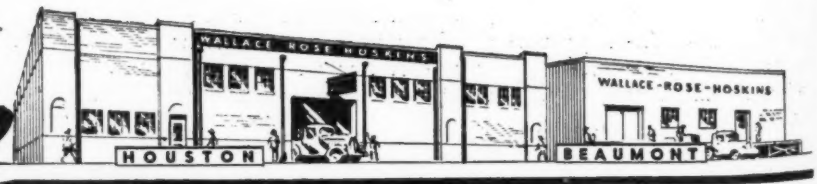

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Caleb E. Hodges, Paraflow laboratories, Standard Oil Company (New Jersey), and A. Bruce Boehm, chemical products department, Stanco Distributors, Inc., presented a paper at the National Petroleum Association at Oil City and the Western Petroleum Refiners Association at Tulsa, May, 1943, that reported on the pourpoint stability of such oils and on the laboratory test developed to predict this stability. More specifically, the data given deal with lube oils blended with Paraflow, a synthetic hydrocarbon oil.

It appears, therefore, that the solvents composed of methanol and ethylene glycol, and of dipropylene glycol and ethylene glycol are essentially selective for hydrocarbon structure. Consequently, a hydrocarbon mixture containing C_7 to C_{10} components can be extracted with these solvents to separate aromatics from paraffins, naphthenes and, to some extent, from olefins. Lower or higher molecular weight components, if present, can smear the seperation in two ways: (1) The solubility of a C_6 non-aromatic can be similar to that of a C_{11}, or higher, aromatic; or (2) the structure of higher aromatics can be so modified by substituents as to change the order of solubility characteristic of a homologous series of aromatics.

Kalichevsky[8] notes that the effect of molecular weight in lubricating oil extraction has been observed. He states that "solvents have also a certain selective action towards the paraffinic type of hydrocarbons of lower molecular weights, which, in some instances, may be more soluble in the solvent than the aromatic compounds of higher molecular weight."

Applications. While aromatic separation from light petroleum fractions has been of immediate importance, other applications of the process can be anticipated. These include the treatment of paraffinic naphthas for industrial solvents, diesel fuels, and burning oils; and of cracked products for motor fuel. Additional fundamental data such as that used in aromatic separation, are required for evalution of some of the applications with respect to costs.

TABLE 3
Operating conditions

Sample no.	1	2	3	4	5
Solvent ratio, lb. solvent, per lb. feed	2.8	3.2	3.7	7.2	7.5
Reflux ratio, lb. reflux, per lb. extract product	5.4	5.0	3.8	2.6	3.5
Yields—					
Extract	30	51	69	42	30
Raffinate	70	49	31	58	70
Aromatic content of:					
Feed, wt. per cent	17	25	56	29	24
Extract	55	62	82	66	85
Recovery of aromatics, per cent	86-99	—*	—*	88-96	—*

*99 per cent indicated from raffinate analysis.

Detailed plant designs have been made for aromatic separation which show the process to be economically feasible. Operating cost decreases with the increase in feed concentration, as is to be expected. For this reason it is often desirable to extract fractions rather than a wide-boiling material. Low feed concentration also limits operation from a practical standpoint. For example, if the concentration of aromatics in the feed of the toluene-Skellysolve *B* system is 5 per cent, 98.7 per cent of the total extract hydrocarbons must be recycled to the column for minimum reflux. Obviously, the split must be a practicable one, and precise control is necessary in any case.

The mixture of glycols fulfills the requirements usually specified for a solvent. It is selective, readily available, cheap (as there need be no loss), stable and non-corrosive in the absence of oxygen, non-reactive with reactive hydrocarbons and is easily recovered. In addition it is versatile: The ratio of the solvents in the mixture can be varied, within limits, to suit a particular feed material or operating condition. A currently desirable property is that lubricating oil extraction equipment using furfural can be converted to other extraction applications with the mixed glycols by the use of approximately 10 per cent additional steel.

Acknowledgments. The assistance of T. B. Braun, Dean Hirshfield, A. M. Rohn, and J. C. St. Clair in the experimental work is acknowledged. J. C. St. Clair evaluated flooding rates and *H.E.T.P.* values. Doctor H. B. Coats, Doctor R. B. Werner and others of the engineering staff made the plant design, plant conversion, and cost studies. The work was under the general supervision of Doctor E. H. Leslie.

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Fig. 7. Extraction of sample 4 with 65 dipropylene glycol + 35 ethylene glycol. Composition of feed and products

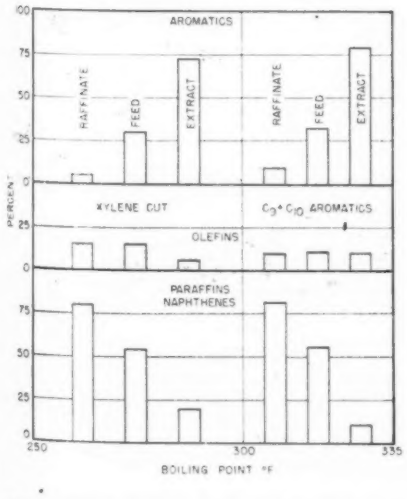
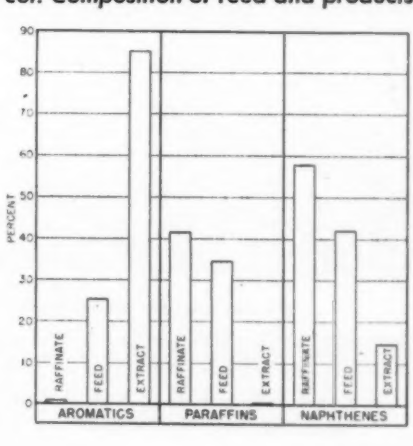


Fig. 8. Extraction of sample 5 with 65 dipropylene glycol + 35 ethylene glycol. Composition of feed and products



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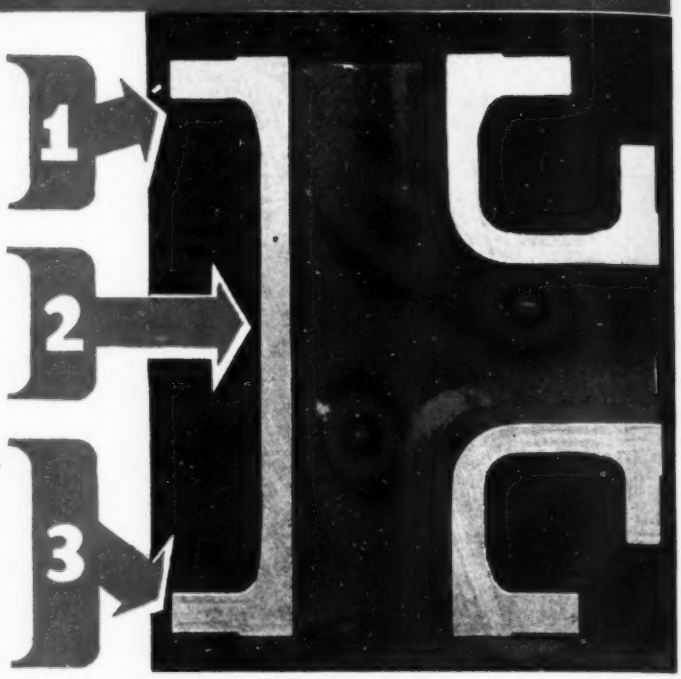

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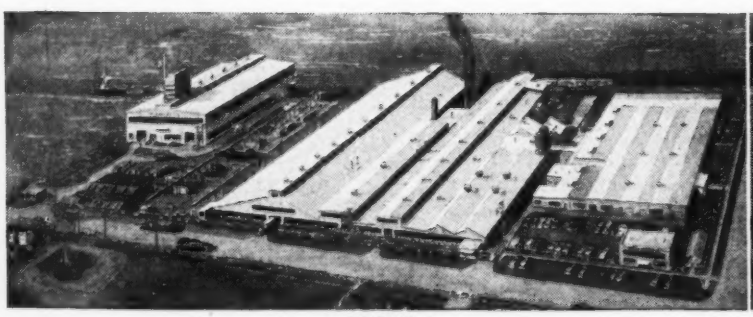

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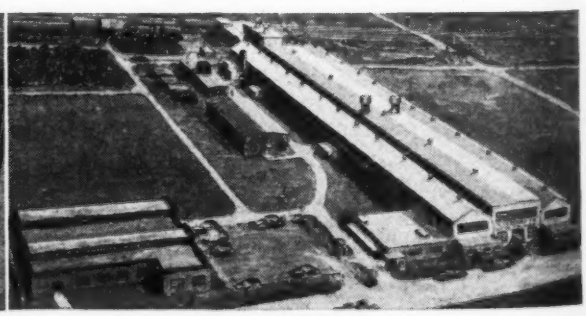

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The Refining of Permian Basin High Sulphur Crudes*

By F. C. MORIARTY
Universal Oil Products Company

THE Petroleum Industry War Council[1] has reached the conclusion that practically all the available capacity in District No. 2 must be utilized to fulfill the long term program designed to produce the maximum quantity of vitally needed petroleum products. To accomplish this, the Council has indicated that runs of high sulphur crude to District No. 2 refineries will rise to 159,000 bbl. per day in the third quarter of 1944 if the region is to keep its total throughput up to program levels. This additional quantity of high sulphur crude will come from the West Texas-New Mexico area.

The introduction of high sulphur crudes to Mid-Continent refineries presents a serious problem. Corrosion rates on carbon steel are extremely high when processing the high sulphur West Texas crudes, many of which contain large quantities of salt that must be removed before the crude oil can be satisfactorily processed. The products from these crudes are high in sulphur content and require special treating methods. Two excellent presentations of the problems of refining of West Texas crudes have been given recently, one by B. L. Scoggins[2] at the Western Petroleum Refiners Association meeting in Tulsa and the other by H. H. Wenzke[3] in the *Oil & Gas Journal*. Since these two papers cover the general problem of processing West Texas crudes, the present discussion is limited to the West Texas crude oil produced from the Permian Basin and more particularly from the Slaughter pool. These crude oils are of special interest at this time since it is from this area that most of the additional production intended for District No· 2 will probably be obtained. Few refiners have processed Slaughter crude and only one refinery has operated on a charge consisting of 100 per cent Slaughter crude.

Table I shows an analysis of Slaughter crude oil and various fractions produced therefrom. It will be noted that the straight run gasoline has a higher octane number than the usual Mid-Continent product. A 21 per cent by volume diesel oil fraction had a cetane number of 50.5. The sulphur content of the various fractions increases in inverse ratio to the A.P.I. gravity. At present, the salt content of the crude produced from this field averages from 200-300 lb. per 1000 bbl. In winter months this may increase to 400-500 lb. per 1000 bbl., and it is quite possible

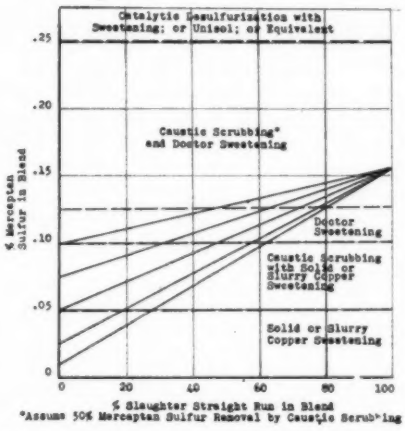


Fig. 1. Recommended treatment for blends of Slaughter straight run with gasolines having various mercaptan contents

that when the production from this field is increased, the salt content from the crude will also increase.

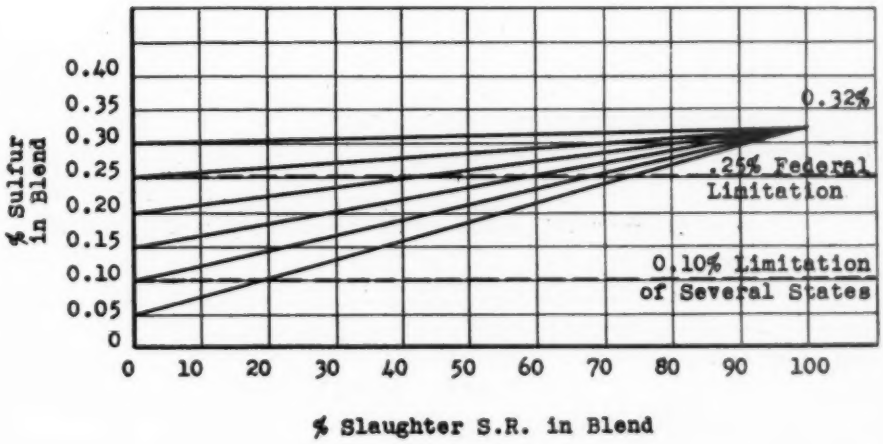
Crude blending. It would be desirable in many respects if conditions permitted refiners to segregate Mid-Continent and West Texas stocks. This would permit the manufacture of the most desirable products from each crude since each is superior to the other in certain respects. Unfortunately, the additional storage facilities and the extensive changes in processing equipment to permit charging straight crudes such as Slaughter will make this an almost impossible consideration during the war period. With this in mind, much of the information in this paper has to do with blends of Slaughter and low sulphur crudes.

Sulphur limitations. When high sulphur crudes must be utilized, the limitations governing total sulphur content present a definite handicap in economically processing these oils. The situation today is not nearly so restricted as it was a few years ago. The federal government specifications covering total sulphur have recently been increased from 0.1 to 0.25 per cent. In recent years, the sulphur limit in most states has been raised to 0.25 per cent. It has been firmly established that sulphur contents of 0.25 per cent or higher in ordinary motor fuel are not injurious to motors. In fact, much gasoline that contained 0.4 per cent total sulphur or higher has been marketed without difficulty. In spite of this, a few states still have a sulphur limit of 0.1 per cent. These arbitrary specifications present an unfair handicap to refiners who process high sulphur crudes and every effort should be made to remove these limitations. In some states, it may be necessary some day to pay a premium for gasolines that contain less than 0.1 per cent sulphur if this specification remains in force. To market gasoline in these states when West Texas high sulphur crudes must be refined, it will be necessary, in most cases, to segregate high and low sulphur stocks; this will require additional storage facilities.

If a large proportion of the gasoline produced from West Texas high sulphur crudes must be marketed at the 0.1 per cent specification, the refiner must resort to expensive methods of processing, such as severe treatment with sulphuric acid.

Salt removal. When considering Slaughter crude oil as charging stock for a refinery, the first major problem will be that of reducing the salt content to a reasonable level. Since large quantities of salt will increase corrosion rates within the refinery and deposit in heater tubes, it is necessary to reduce

Fig. 2. Slaughter straight run gasoline blended with gasoline "X." No sulphur reduction



*Presented before Western Petroleum Refiners Association, Wichita, Kansas, October 19, 1943.

the salt content to a low value. Reduction to less than 25 lb. per 1000 bbl. is generally recommended.

It has been estimated that approximately 50 per cent of the salt present in Slaughter crude is in crystalline form. In view of this, it is difficult to reduce the total salt content to a satisfactory level by conventional methods of desalting. If electrical methods are employed, satisfactory results probably will be obtained if the salt content of the crude is below 200 lb. per 1000 bbl.; above this figure, two-stage electrical desalting may be necessary. One refiner is now reducing the salt content of this crude from 200-400 lb. of salt per 1000 bbl. to 15-20 lb. by a two-stage non-electrical process. The second stage of this process is a typical salt settler operating at 325 °F. The details of the first stage of this process cannot be disclosed at this time but it is hoped that permission to do so will be granted in the near future.

To illustrate the difficulty of removing salt from this crude, a typical single stage salt settler operating at 350° F. was only about 50 per cent efficient. The most practical method of handling the salt concentration of this crude may be to charge only blends of Mid-Continent and Slaughter crude in which the percentage of Slaughter is sufficiently low so that a high salt content is not obtained. If blends are used, the conventional salt settling equipment may prove satisfactory.

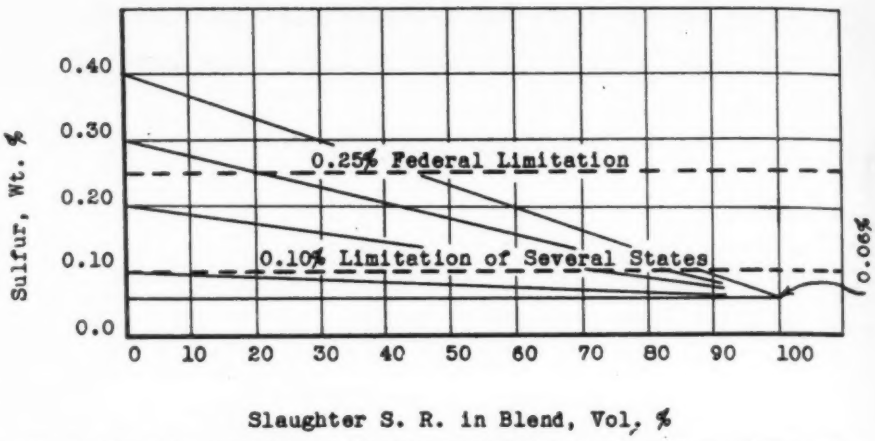


Fig. 5. Slaughter straight run blends, desulphurization treatment. Temperature, 700°F.; pressure, 20 lb. per sq. in.; space velocity, 1.0

Those refineries producing asphalt may find this a convenient method of avoiding the salt problem. Slaughter crude contains 20-25 per cent of 100-penetration asphalt of high quality. Reduction of the crude to asphalt produces a salt-free gas oil that can be used as charging stock to cracking.

Crude distillation. From an operating standpoint the processing of this crude in a topping unit will be much the same as when charging Mid-Continent crude oils. The corrosion rates and maintenance will be somewhat higher than when processing Mid-Continent oils but, in general, carbon steel equipment can be used unless temperatures in excess of 600 to 650° F. are encountered. Ammonia should be introduced into the overhead stream from the crude column to prevent hydrochloric acid corrosion in the overhead condensing system. It is recommended that ammonia be added either to the top tray or directly into the vapor line. If ammonia is added low in the column, deposits will be formed on the bubble trays.

The treatment of the straight run products from Slaughter crude oils requires special consideration.

Considerable hydrogen sulphide is evolved in crude distillation, and the straight run gasoline should be caustic washed immediately to remove all traces of hydrogen sulphide before going to rundown storage. If gasoline containing hydrogen sulphide reaches the rundown tanks, some oxidation may occur, causing the formation of free sulphur that may make the final product corrosive. The presence of hydrogen sulphide in gasoline storage will also increase corrosion of storage equipment and, since it is extremely poisonous, presents a potential hazard.

Gas masks should be worn at all times when gauging tanks where there is a possibility of the presence of hydrogen sulphide.

If the percentage of Slaughter crude oil is high in the charge, a large amount of caustic soda will be consumed in removing the hydrogen sulphide. For this reason, it may be profitable to install a stabilizer on the straight run gasoline stream for the purpose of removing hydrogen sulphide along with propane and lighter fractions.

The straight run gasoline prepared from Slaughter crude averages from 0.15-0.175 wt. per cent mercaptan sulphur at 400 °F. endpoint. The mercaptans present in this gasoline are pre-

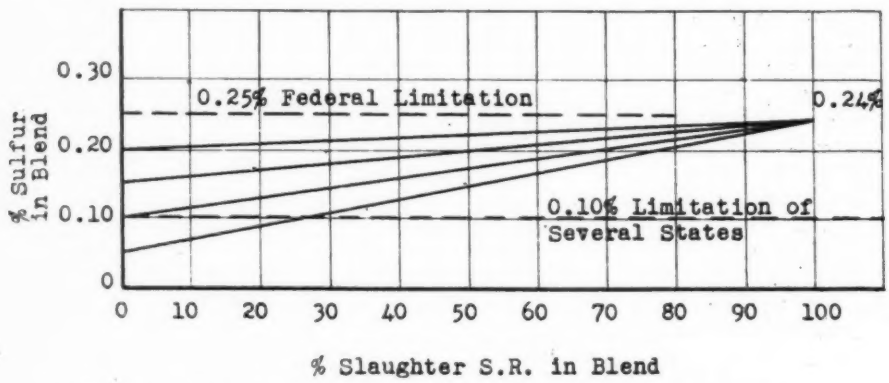


Fig. 3. Slaughter straight run gasoline blended with gasoline "X." Mercaptan sulphur of Slaughter gasoline reduced 50 per cent

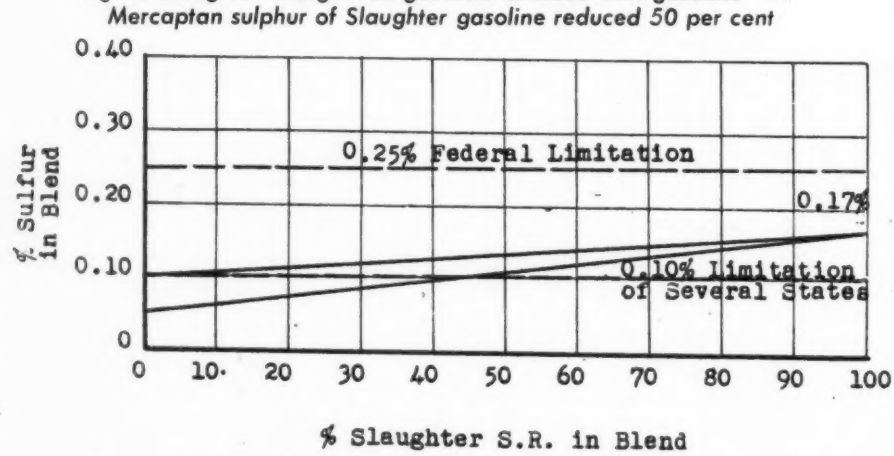


Fig. 4. Slaughter straight run gasoline blended with gasoline "X." Slaughter gasoline Unisol treated

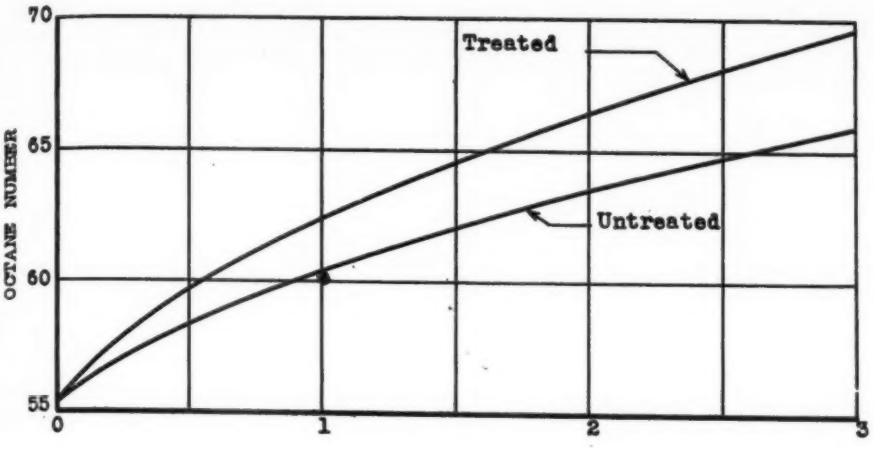


Fig. 6. Effect of Unisol treating on lead susceptibility of Slaughter 400°F. endpoint straight run gasoline

dominantly high boiling and somewhat difficult to remove by the usual regenerative type caustic scrubbing unit. With a typical caustic scrubbing unit such as that now operated by many Mid-Continent refiners, not more than 50 per cent mercaptan removal can be expected. Since it will be almost impossible to charge straight Slaughter crude oil to a typical Mid-Continent refinery, Fig. 1 has been prepared for the purpose of studying the effect of various percentages of gasoline produced from crude Slaughter blended with others of lower sulphur content. To use this figure, choose the line running diagonally from 0.155 per cent mercaptan sulphur, which corresponds to 100 per cent Slaughter straight run at 400 °F. endpoint, to a point on the zero per cent Slaughter straight run line which represents the mercaptan content of the present straight run gasoline. Using this line as a base, the per cent of mercaptan sulphur that will be produced from any blend of other gasoline and Slaughter can be directly determined and used as an index for the blending of crudes. The horizontal dotted lines on the chart represent marginal limits of various treating processes. These limits should be used with some caution since equipment design factors may affect these limitations. In many cases the various processes mentioned can be operated at higher mercaptan levels than indicated, but, in general, at higher levels can be expected to present operating problems and require special controls.

It will be noted that, even though caustic scrubbing is assumed to remove only 50 per cent of the mercaptan sulphur, this greatly increases the operating limits of doctor sweetening or copper sweetening units. For example, assume that a Mid-Continent straight run gasoline containing 0.025 per cent mercaptan sulphur is blended with Slaughter straight run. Without caustic scrubbing, copper sweetening is not recommended if the percentage of Slaughter straight run in the blend exceeds 19 per cent. If the Slaughter straight run is first caustic scrubbed to remove 50 per cent of the mercaptan sulphur present, 57 per cent of Slaughter straight run can be used in the blend. This indicates that many refiners in this area can utilize present treating equipment if a caustic scrubbing unit is added and a reasonable percentage of Slaughter used.

For concentrations of mercaptan above 0.25 per cent, only catalytic desulphurization or mercaptan extraction

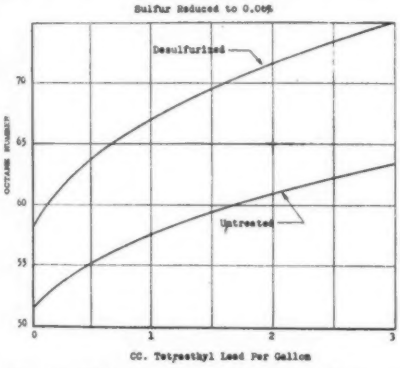


Fig. 7. Effect of desulphurization on lead susceptibility of Slaughter 400°F. endpoint straight run gasoline. Desulphurization conditions: 700°F., 20 lb., 1.0 liquid hourly space velocity, over Silvertown clay. Sulphur reduced to 0.06 per cent

Fig. 8. Recommended treatment for blends of Slaughter cracked gasoline with gasolines having various mercaptan contents

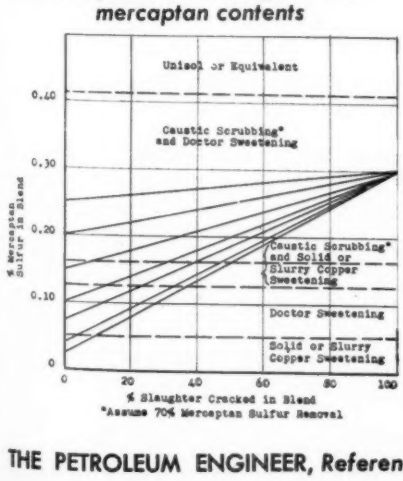


TABLE I

Fraction	Crude oil	375 °F. endpoint gasoline	Dr. swt. 375 °F. endpoint gasoline	Gas oil	Topped crude after		Dist. Loss
					375 °F. endpoint gasoline	Gas oil	
Yield vol. per cent of crude oil	100.00	31.7		21.7	68.1	47.0	0.2
Analyses of fractions:							
Gravity, °A.P.I. at 60 °F.	31.6	56.6	56.5	36.1	22.2	16.8	
Sp. gr. at 60 °F.	0.8676	0.7523	0.7527	0.8443	0.9206	0.9541	
Total sulphur, per cent	2.02	0.28		1.23	2.75	3.25	
Mercaptan sulphur, per cent		0.117*					
R.V.P., lb. per sq. in.		6.2	5.2				
Octane No., M.M.		56.5	55.0				
Octane No., M.M.+1cc. TEL.			61.0				
Octane No., M.M.+3cc. TEL.			68.5				
Cold test, °F.	−5			below 0	50	65	
BS&W, per cent	0.2				0.2	0.3	
Viscosities:							
Kinematic at 100 °F., Cs.	5.52			2.42	39.68	409.3	
Kinematic at 210 °F., Cs.					6.10	20.95	
Univ. at 100 °F., Sec.	44.0			34.2	184	1890	
Univ. at 210 °F., Sec.					45.8	101.5	
Aniline No., °F.				139.6			
Aniline No., °C.				59.8			
Cetane No.				50.5			
100 ml. distillation:							
I.B.P., °F.	134	107	115	404	425	619	
5 per cent	189	150	153	422	458	637	
10 per cent	226	166	173	431	481	653	
20 per cent	290	190	196	446	527	671	
30 per cent	371	207	214	460	584	698	
40 per cent	480	225	230	473	639	713	
50 per cent	570	243	247	485	680	729	
60 per cent	647	262	264	500	691	738	
70 per cent	681	282	283	515	703	749	
80 per cent	716	305	303	534	713	758	
90 per cent	750	332	333	563	720		
End point	754	374	376	619	720	760+	
Per cent over	96.0	98.5	98.5	99.0	93.0+	92.0	
Per cent bottoms		1.0	1.0	1.0			
Per cent loss		0.5	0.5				
Per cent coke by weight	3.8				5.9	7.8	
Per cent over at 400 °F.	32.5						
Per cent over at 572 °F.	50.2			93.0	28.5+		

*Lower than average; apparently some oxidation had taken place during shipment of sample.

processes should be used. Since these processes reduce total sulphur content and increase octane number they will compare favorably with sweetening processes at much lower levels of mercaptan content. In most cases, these processes can be expected to pay their way even if the mercaptan content is in a low range.

Fig. 2 shows the effect of blends of Slaughter straight run gasoline upon the total sulphur content of various gasoline blends. It can readily be seen from this chart that since the total sulphur content of Slaughter straight run gasoline is approximately 0.32 per cent, a reasonable percentage of low sulphur gasoline must be blended with it in order to meet the federal limitation of 0.25 per cent on total sulphur content. Very little Slaughter can be used if it is necessary to meet the 0.10 per cent limitation of several states.

If caustic scrubbing is used, the total sulphur content is reduced to 0.240 per cent, which is slightly below the federal limitation. This is shown graphically by Fig. 3.

Fig. 4 shows the effect of removing all of the mercaptan sulphur from Slaughter straight run gasoline.

Fig. 5 shows the effect of catalytic desulphurization with Silvertown clay at 700 °F. 20 lb. per sq. in. and space velocity 1.0 upon the total sulphur content. It will be noted from this chart that catalytic desulphurization will produce an extremely low total sulphur content gasoline from Slaughter straight run which easily meets the 0.10 per cent limitation. Since the cracked gasoline produced from Slaughter crude oil is extremely high in total sulphur content, it may be desirable to desulphurize catalytically the straight run gasoline in order to blend the desulphurized product with the higher sulphur content cracked gasoline in order to meet the federal limitation of 0.25 per cent.

Fig. 6 shows the effect of Unisol treating on the tetraethyl lead susceptibility of Slaughter straight run gasoline.

Fig. 7 shows the effect of catalytic desulphurization on the tetraethyl lead susceptibility of Slaughter straight run.

With reference to Figs. 6 and 7, it should be pointed out that, in many cases, the usual sweetening processes decrease the octane number of the gasoline. Identical samples were not used to obtain the data from which Figs. 6 and 7 were prepared. Although both these samples were 400 °F. endpoint Slaughter straight run, the untreated clear octane numbers were not the same. This was attributed to a difference in the boiling range of the light fractions.

The kerosine produced from Slaughter crude oil is high in aromatic and total sulphur content. Lamp quality kerosine cannot be produced from this crude oil unless unusually severe treating methods are employed. Kerosine suitable for stove oil can be produced from Slaughter crude by acid treatment or high temperature desulphurization.

Although high in total sulphur content, satisfactory burner distillates can be produced from this crude. It may be desirable to market a maximum quantity of this material as burner distillate and by so doing conserve the quantity of low sulphur oils available as charging stock to the cracking units.

Cracking. From the standpoint of processing there are no particular operating problems involved in cracking Slaughter crude oil. Corrosion rates, however, are extremely high and extensive use of corrosion resistant alloys is required to prevent rapid depreciation

Synthesis and Properties of Hydrocarbons of High Molecular Weight

The work during the last year of American Petroleum Institute Research Project 42 at The Pennsylvania State College on the synthesis and properties of hydrocarbons of high molecular weight is summarized in a paper by R. W. Schiessler, Pennsylvania State College, D. G. Clarke, Rohm and Haas Company, C. S. Rowland, Interchemical Corporation, W. S. Sloatman, American Cyanamid Corporation, and C. H. Herr, Pennsylvania State College.

Twenty-four new hydrocarbons ranging in molecular weight from 326 to 479 were prepared, making a total of 66 pure hydrocarbons of high molecular weight reported by this project since its inception in July, 1940. The physical properties determined for each of the hydrocarbons are as follows:

1. **Kinematic viscosity at 32, 68, 100, 140, and 210° F.; Saybolt Universal viscosity calculated for 100 and 210° F.**
2. **Kinematic viscosity index by the Dean and Davis method.**
3. **Density at 32, 68, 100, 140, and 210° F.; gravity in deg. A.P.I. calculated.**
4. **Melting point from the melting curve.**
5. **Boiling point at 0.50 mm. and 1.00 mm. from vapor-pressure curve over the range 0.50 mm. to 10.0 mm. pressure.**
6. **Heat of vaporization, calculated for the range 0.50 mm. to 10.0 mm. pressure.**
7. **Aniline point, reported in deg. C and deg. F.**
8. **Refractive index at 20, 30, and 40° C.**
9. **Specific and molecular refraction, calculated for 20° C.**
10. **Molecular volume, calculated at 20° C.**

These data have been employed in checking the work of Kurtz and Lipkin on molecular volume, the method of calculating refractive index of Lipkin and Martin, and the correlation of refractive-index change and density change of Ward and Kurtz. In addition, the methods of predicting percentage naphthenic rings in oils of Davis and McAllister, of Waterman, and of Lipkin and Kurtz have been applied to the pure hydrocarbons and thus evaluated.

The paper was presented before the division of refining at the annual meeting of the American Petroleum Institute in Chicago, Illinois, November 10, 1943.

Fig. 9. Slaughter cracked gasoline blended with gasoline "X." No sulphur reduction

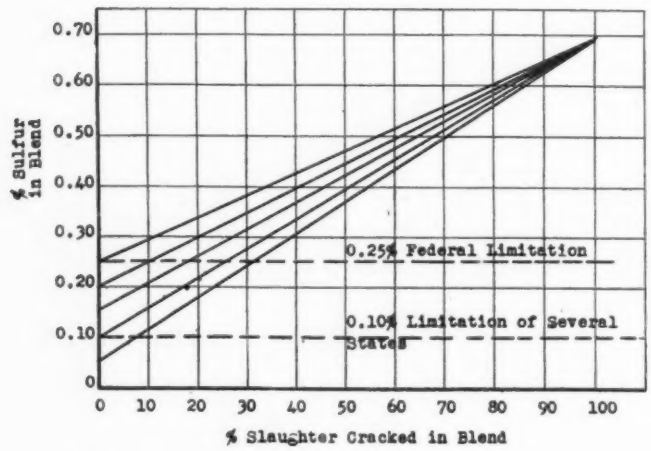
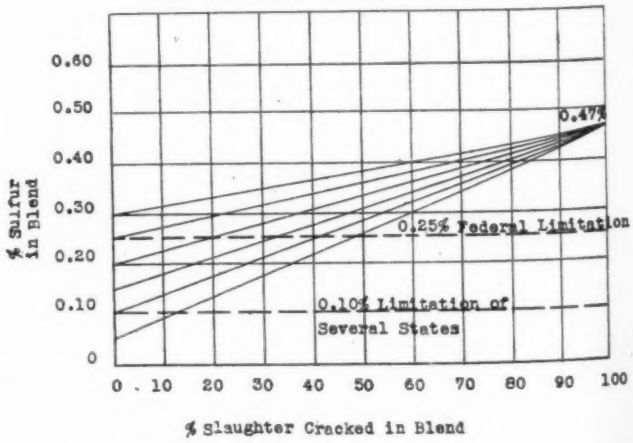
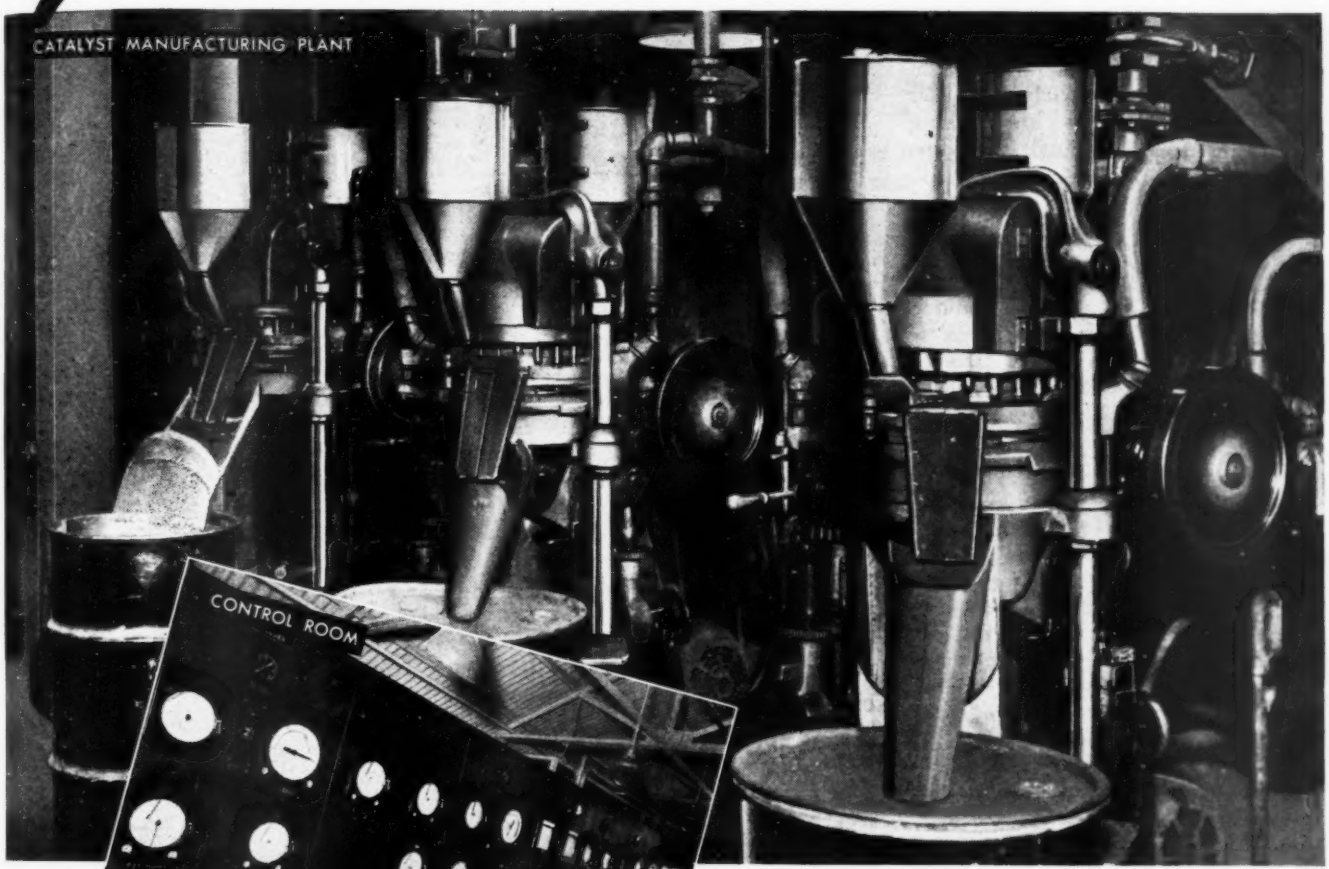
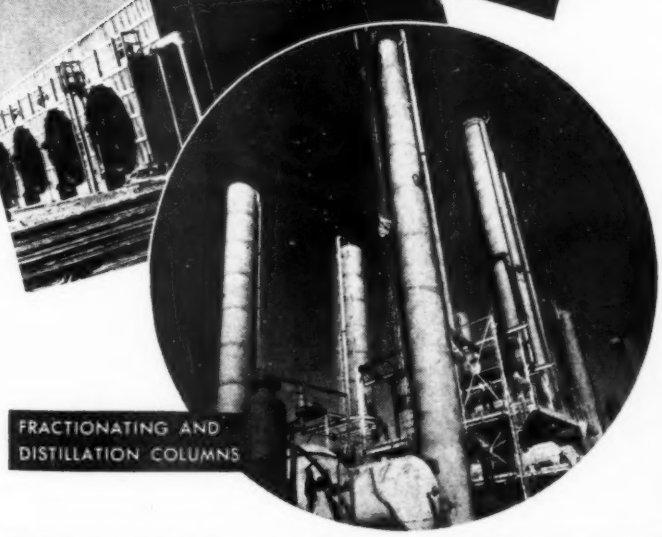


Fig. 10. Slaughter cracked gasoline blended with gasoline "X." Mercaptan content of Slaughter gasoline reduced 70 per cent by caustic scrubbing



Toluene FROM PLAN TO PLANT





These units for the production of synthetic Toluene, the basic ingredient of TNT, were designed and built by Fluor under license from Shell Oil Co., Inc. This plant which produces enough nitration grade, high purity Toluene to fill 700 "block-busters" every day was completed and in operation less than one year after Pearl Harbor.

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of equipment. The addition of lime is an effective method of reducing corrosion rates in cracking equipment. The amount of lime that can be added is usually dictated by the BS&W content of the fuel oil. The usual quantity of lime that is added to a topped crude oil of this sort is approximately ½ lb. per bbl. It is recommended that cracking unit heater tubes and headers be constructed of 8 per cent chrome steel.* Alloy linings are required in the larger vessels and 11-13 chrome steel is preferred for this service. Gannister linings can be used in some of the larger vessels but these linings have a much shorter life. In all cases where temperatures between 650 to 850° F. are encountered, high corrosion rates can be expected unless special alloys or linings are used.

The cracked residuum will be high in sulphur content but otherwise entirely suitable as a heavy fuel oil.

The cracked gasoline should be immediately stabilized to remove hydrogen sulphide. If the cracked gases are charged to codimer units these are usually equipped with a depropanizer that will remove hydrogen sulphide along with propane and lighter fractions. The butane-butylene charge to the codimer unit will contain a considerable amount of light mercaptans and it may be necessary to remove these by caustic scrubbing.

If the light cracked gases are charged to a polymerization unit for the purpose of producing polymer for motor gasoline, a depropanizer can not be used for the purpose of hydrogen sulphide removal without also removing propylene, which will materially reduce the amount of polymer produced. In this case it is recommended that one of the regenerative type hydrogen sulphide removal processes such as the tripotassium phosphate process of the Shell Oil Company or the Girbotol process of the Girdler Corporation be used.

*Wenzke[3] mentions that 4-6 per cent chrome gave reasonable service in one instance.

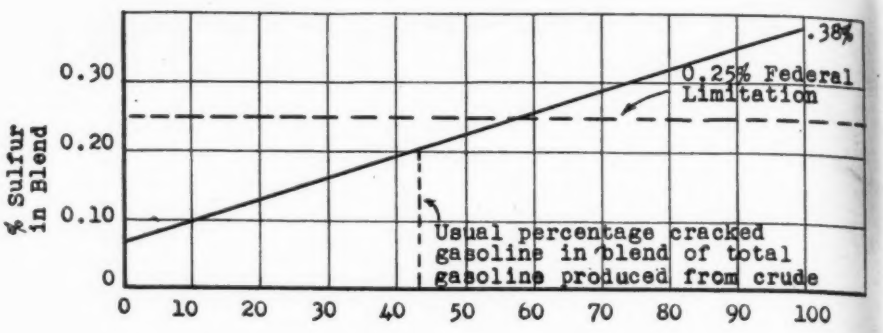
% Sulfur in Blend
0.30
0.20
0.10
0
.38%
0.25% Federal Limitation
Usual percentage cracked gasoline in blend of total gasoline produced from crude
0 10 20 30 40 50 60 70 80 90 100
% Slaughter Unisol Treated Cracked Gasoline in Blend

Fig. 13. Slaughter cracked Unisol treated gasoline blended with desulphurized straight run

The cracked gasoline is extremely high in mercaptan content. A commercial unit now operating on 100 per cent Slaughter crude oil produces a cracked gasoline containing 0.30 per cent mercaptan sulphur. As an example of how difficult this might be in a process in a typical refinery operating a doctor sweetening unit, assuming 1000 bbl. per day was charged to the doctor sweetening unit, it would be necessary to regenerate 2750 lb. of litharge per day. This would require enormous doctor regeneration facilities to say nothing of the problem of adequately mixing doctor solution and gasoline or recovering the lead sulphide. Figs. 8, 9, 10, 11, and 12, were prepared to show the effects of various percentages of Slaughter cracked gasoline blended with gasoline of a lower sulphur content. The charts are similar to those previously mentioned for straight run gasoline and need no further explanation.

Catalytic desulphurization such as represented by the Phillips bauxite process or the Gray high temperature clay treating process is not generally recommended for cracked gasoline which is to be sold as ordinary motor fuel. First, catalyst life is very short in this service; and, second, the distribution of the sulphur compounds present is not favorable to this method of processing. Cracked gasolines predominate in mercaptans and ring sulphur compounds. Catalytic desulphurization has little, if any, effect upon the ring sulphur compounds and although this method of desulphurization will remove the mercaptans, these can be extracted from the gasoline by less costly processes.

If the straight run from Slaughter crude oil is catalytically desulphurized and the cracked gasoline is Unisol treated to remove all the mercaptans present, the two products can be blended as produced from the crude oil and a final blend obtained that contains less than the 0.25 per cent federal limitation on total sulphur. This is shown in Fig. 13. These methods of processing make it possible at a reasonable cost to meet this limitation without resorting to expensive and wasteful acid treating. The saving in tetraethyl lead that results from the use of these two processes ordinarily will be sufficient to permit the rapid retirement of the initial installation cost of the equipment.

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1. P.I.W.C. report, "Facilities for Processing Sour Crude Needed to Meet Refinery Program;" *Oil and Gas Journal*, 42, 23, 26 (1943).
2. B. I. Scoggins and G. H. Burruss, *Oil and Gas Journal*, 42, 24, 61 (1943).
3. H. H. Wenzke, *Oil and Gas Journal*, 42, 23, 43 (1943).

Fig. 11. Slaughter cracked gasoline blended with gasoline "X." Slaughter gasoline Unisol treated with 100 per cent mercaptan sulphur removal

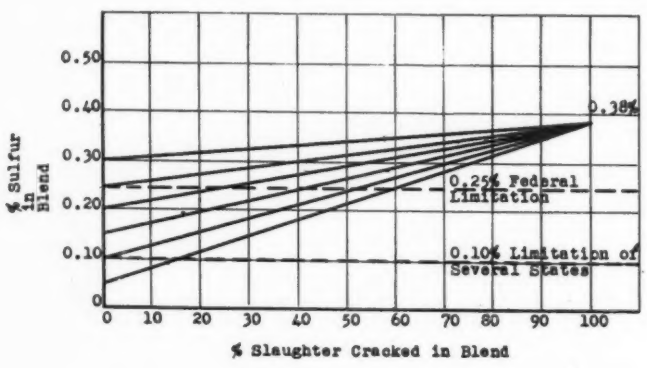
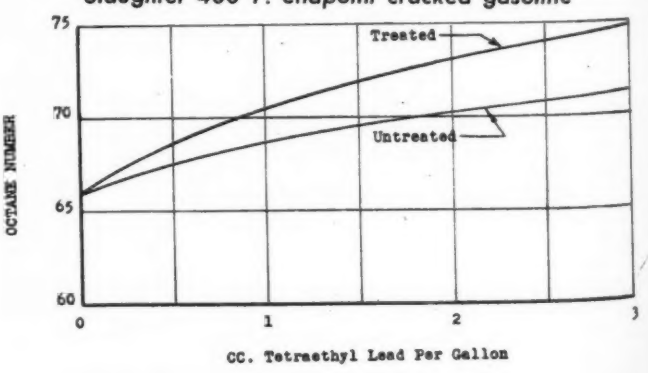
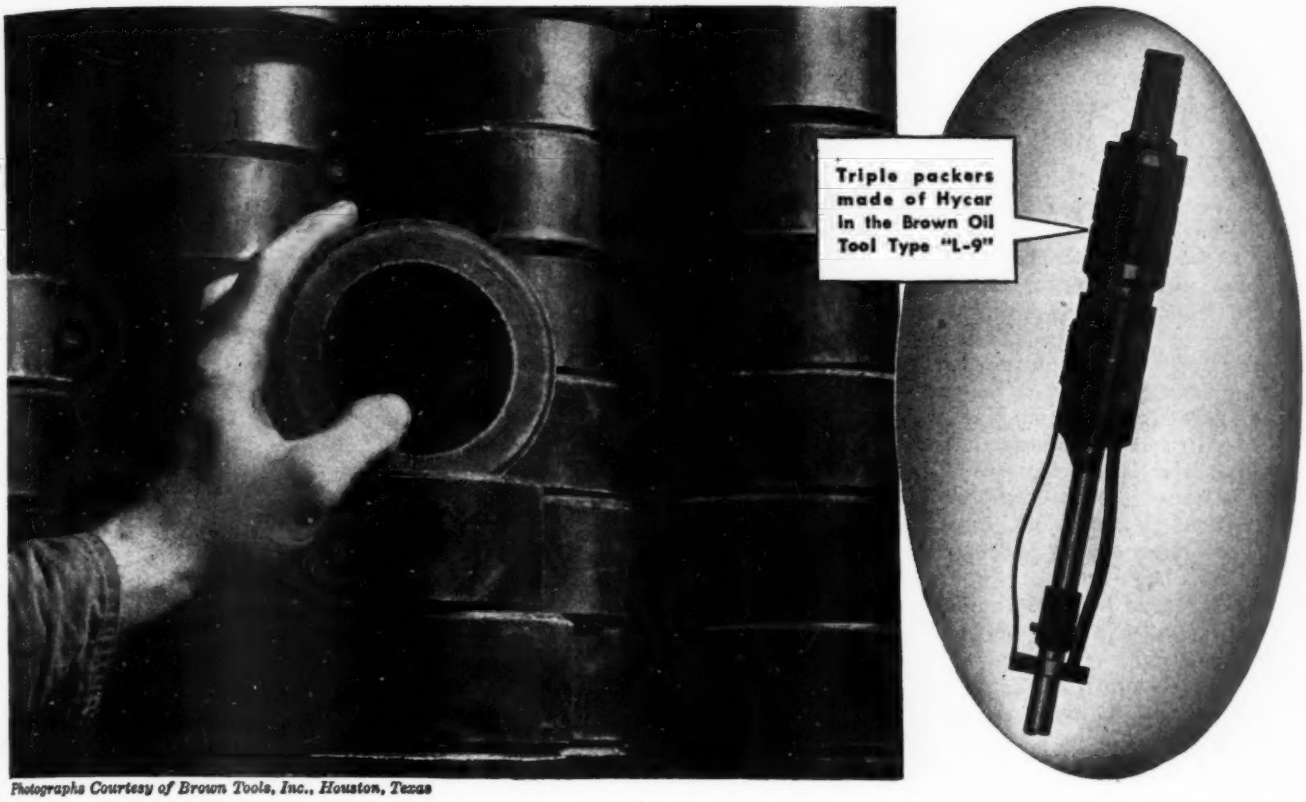


Fig. 12. Effect of Unisol treating on lead susceptibility of Slaughter 400°F. endpoint cracked gasoline





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The Development of the Hydrogen Fluoride Alkylation Process*

By C. G. GERHOLD, J. O. IVERSON, H. J. NEBECK, and R. J. NEWMAN
Universal Oil Products Company

INTRODUCTION. The hydrogen fluoride alkylation process is now playing an important role in the program to secure the maximum production of aviation gasoline for the fighting forces. The development of this process involving the first large-scale utilization of HF as a catalyst presented many new problems of interest to the chemical engineering profession. The purpose of this paper is to present the story of the commercial development of the process, and to describe the problems involved and their solutions.

Brief history of the process. The paraffin alkylation reaction, which is the interaction of isoparaffin and olefin hydrocarbons to produce highly branched paraffinic motor fuels, was discovered by V. N. Ipatieff and Herman Pines more than a decade ago at the Research and Development Laboratories of Universal Oil Products Company.

Since the time of this fundamental discovery, extensive laboratory and pilot-plant experimentation has been carried on to study the reaction with several catalysts.[1,2,3] Investigations by Carl B. Linn and A. V. Grosse indicated that concentrated HF was an excellent catalyst for alkylating isobutane with propylene, butylene, or amylenes. The olefins were completely converted in the presence of an excess of isoparaffin to give a saturated product with excellent anti-knock properties boiling almost entirely in the aviation gasoline range.

Although the catalytic properties of HF were attractive, the commercialization of the process was delayed, largely because of the nature of HF and the lack of experience in handling it in the manner and quantities required for hydrocarbon processing. When it became apparent that the facilities for the production of aviation gasoline would have to be expanded to supply the war needs, the development of the HF process was rapidly accelerated. Pilot plant tests for the investigation of charging stocks, operating conditions, and materials of construction, and process and mechanical designs of commercial plants, that normally would have required years, were forced through in a matter of months.

Two major advantages of HF alkylation over the older sulphuric acid process result from the higher process temperature that can be used and the greater ease of catalyst regeneration. The higher temperature permits use of cooling water to remove the heat of reaction and thus eliminates critical refrigerating equipment. Catalyst regeneration is included as a feature of the process in its commercial application. The problem of spent catalyst disposal is serious in many refineries using sulphuric acid alkylation. Catalyst consumption is so low that the raw material and plant requirements for catalyst manufacture are considerably smaller than those for a sulphuric acid alkylation unit on the basis of equal alkylate production.

Properties of hydrogen fluoride. Many chemical engineers remember hydrofluoric acid as an extremely corrosive material kept in a wax bottle in a school storeroom and used for classroom demonstrations of glass etching; and they were probably warned of the dangerous nature of the material. Fortunately the concentrated hydrogen fluoride used in the alkylation process is not corrosive to steel. It is extremely corrosive to the skin but prompt and proper treatment stops the action immediately and prevents painful destruction of tissue.

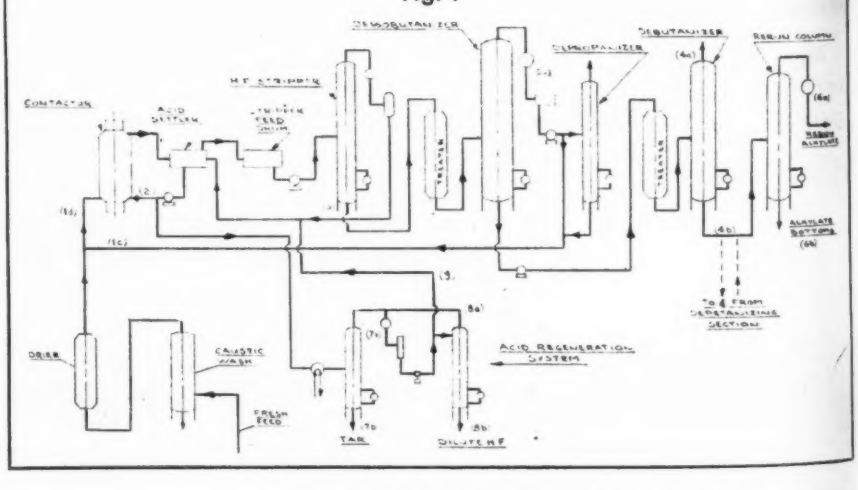
Anhydrous hydrogen fluoride boils at 67.8° F. and has a specific gravity of 1.00 at 32° F. and a viscosity approximately equal to that of water. It is slightly soluble in paraffin hydrocarbon and is miscible with water. HF is a powerful dehydrating agent, which cannot be dried by ordinary chemical means. It forms a maximum boiling solution with water that contains approximately 37 per cent HF. The catalytic and physical properties of HF have been described in a recent article.[4]

Hydrogen fluoride is prepared by treating fluorspar with concentrated sulphuric acid in steel equipment at temperatures ranging from 300° to 400°F. The equipment of the manufacturing plant is made of steel. Solutions containing not more than 40 per cent water are shipped in steel containers or tank cars. The available supplies of HF before the war were not sufficient to meet the requirements of this process, and it was necessary to expand existing manufacturing facilities.

Hazards in handling HF. Hydrogen fluoride must be regarded as a potentially hazardous material, but years of experience in the manufacture of HF in large quantities without a disproportionate share of accidents are proof that the material can be handled safely. Many devices were developed and incorporated into the design for protecting the operating personnel. Accidents, however, may occur in any plant in spite of the most rigid safety regulations and the best of safety devices. In view of this fact an exhaustive study was made of the methods of handling HF and the treatment of HF burns.

Concentrated HF has a triple action on contact with the skin in that it has a dehydrating effect, it acts as a strong acid, and it catalyzes the destruction of tissue causing deep, slow-healing burns. First-aid and medical treatment of burns in general are directed toward removal and neutralization of the acid and precipitation of the fluorine as an insoluble salt. In the past anhydrous HF was not used in large quantities and HF burns were uncommon; moreover, some of the methods for treating an ordinary burn were entirely unsuitable for HF injuries. Therefore, the latest medical informatiotn on the treatment

Fig. 1



*Presented before American Institute of Chemical Engineers, Pittsburgh, Pennsylvania, November 15, 1943.

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DIMENSIONS AND RATINGS

4000 lb at 150 F
600 lb at 750 F — 475 lb at 1000 F

DIMENSIONAL DETAILS

SIZE	1/8"	1/4"	3/8"	1/2"
End to end—Globe	1 13/16	1 13/16	2 1/4	2 3/4
Center to end—Angle	29/32	29/32	1 1/8	1 3/8
Center to top—Open	3 5/8	3 5/8	3 7/8	4
Port diameter	1/8	3/16	1/4	3/8
Weight—lb	1	1	1 1/4	1 1/2

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EDWARD *Steel* VALVES

of HF burns was supplied by U.O.P. in the form of a book by A. J. Carlson[5] to the doctors in the vicinity of the plants.

Process flow of hydrogen fluoride alkylation. The flow of a typical HF alkylation unit is shown in Fig. 1. Charging stock to the plant passes through charge pretreaters which remove organic impurities and water that would otherwise contaminate the products or catalyst. After pretreatment the charge is combined with recycle isobutane and fed to the reaction system. The reaction is carried out in contactors equipped with efficient mixing devices, which maintain intimate contact between the hydrocarbon and catalyst phases and with cooling coils which remove the heat of reaction. The effluent from the contactors passes to a settler in which separation of the catalyst from hydrocarbon is made, the catalyst being returned to the reaction vessel and the hydrocarbon being fed to the fractionation system.

The hydrocarbon stream leaving the settler contains a small amount of dissolved hydrogen fluoride and some organic fluorides. The first fractionation column strips the hydrogen fluoride from the hydrocarbons, and the HF is returned to the reaction zone.

The bottoms from the stripper are fed to a treating section, in which fluorides are broken down and the liberated HF removed. The effluent from this treater is fed to a deisobutanizer, in which the isobutane is separated from the other hydrocarbons. This separation is necessary because a satisfactory alkylation operation requires high isobutane concentration in the contactor. This high concentration is obtained by recycling isobutane.

Bottoms from the deisobutanizer are charged to a debutanizer, where normal

Fig. 3

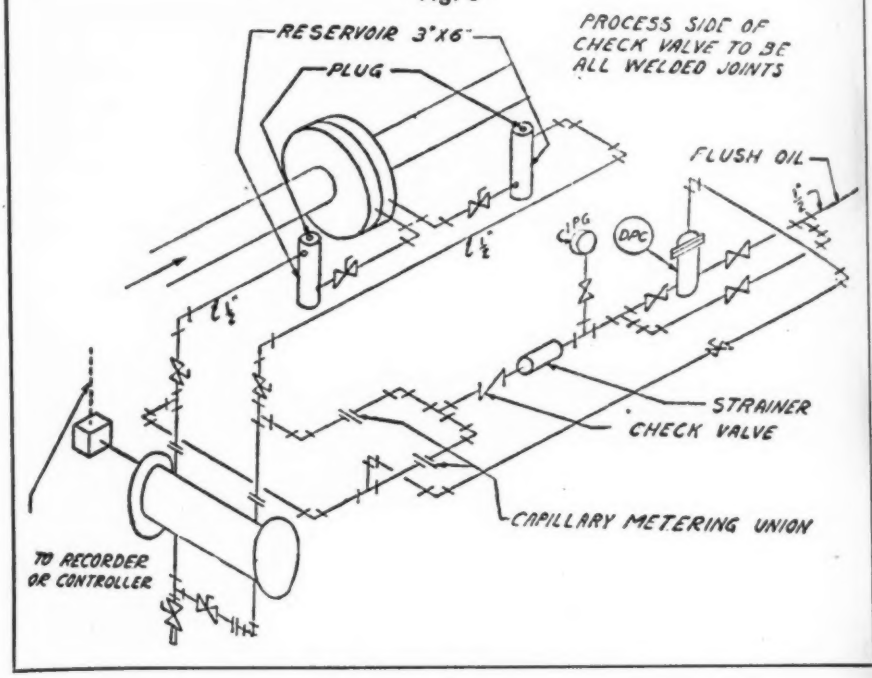
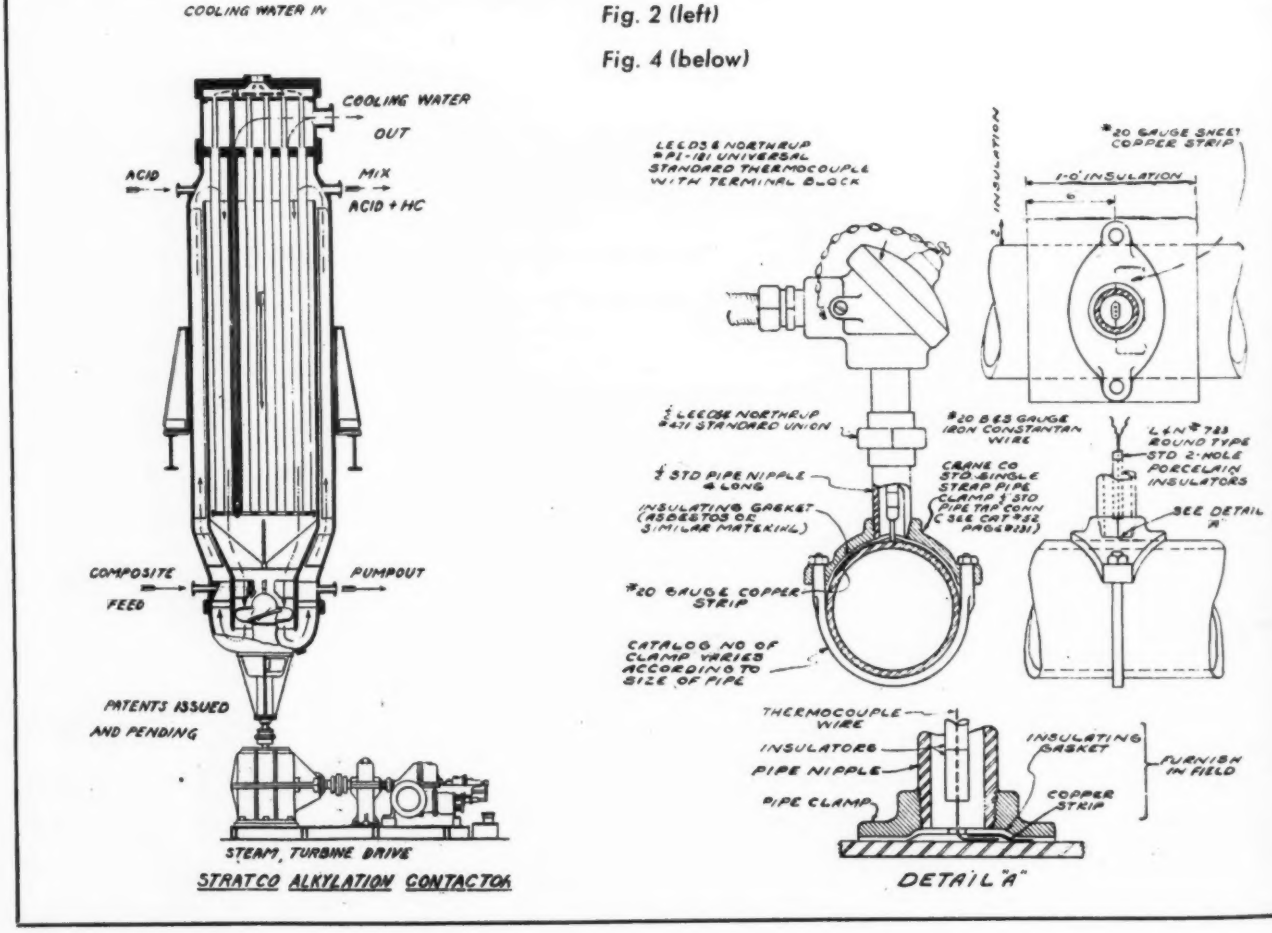


Fig. 2 (left)

Fig. 4 (below)


COOLING WATER IN
COOLING WATER OUT
ACID
MIX ACID + HC
COMPOSITE FEED
PUMPOUT
PATENTS ISSUED AND PENDING
STEAM TURBINE DRIVE
STRATCO ALKYLATION CONTACTOR
LEEDS & NORTHRUP #P1-181 UNIVERSAL STANDARD THERMOCOUPLE WITH TERMINAL BLOCK
#20 GAUGE SHEET COPPER STRIP
1-0" INSULATION
INSULATION
LEEDS NORTHRUP #431 STANDARD UNION
#20 B&S GAUGE IRON CONSTANTAN WIRE
L&N #783 ROUND TYPE STD 2-HOLE PORCELAIN INSULATORS
SEE DETAIL A
STD PIPE NIPPLE 4" LONG
CRANE CO STD SINGLE STRAP PIPE CLAMP STD PIPE TAP CONN (SEE CAT #52 PAGE 231)
INSULATING GASKET (ASBESTOS OR SIMILAR MATERIAL)
#20 GAUGE COPPER STRIP
CATALOG NO OF CLAMP VARIES ACCORDING TO SIZE OF PIPE
THERMOCOUPLE WIRE
INSULATORS
PIPE NIPPLE
PIPE CLAMP
INSULATING GASKET
COPPER STRIP
FURNISH IN FIELD
DETAIL "A"

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HOUDRY CATALYTIC PROCESSES

butane is removed as overhead. The aviation alkylate is distilled from the debutanized total alkylate in the final fractionation step.

Some propane is always present in the charge to an alkylation plant, and it must be removed from the system. In the case of alkylation operations in which the amount of propane is small, it is removed by depropanizing a portion of the recycle isobutane as shown in the flow diagram. When propane constitutes a substantial portion of the feed, depropanizing and HF stripping of the reactor effluent are carried out in a depropanizer and stripper of modified design.

Units for alkylating with amylenes have, in addition to the equipment shown, two fractionation columns for the recovery of high octane number isopentane and the elimination of low octane number normal pentane.

As a result of side reactions, hydrocarbons of high molecular weight and low hydrogen content accumulate in the catalyst phase. In order that the activity may be kept at the desired level, these hydrocarbons are removed in a regenerating distillation step, in which the tars are taken out as bottoms and purified HF is removed as overhead. Accumulation of water in the catalyst phase is prevented by a second regeneration step, in which a part of the overhead from the first step is redistilled to remove water in the form of a constant-boiling mixture containing about 37 per cent HF. Regenerated catalyst is returned to the reaction zone.

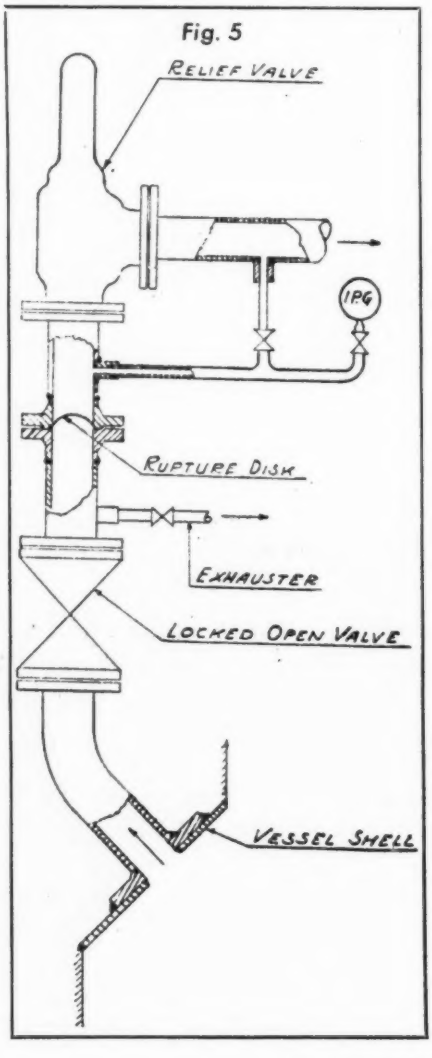
Investigations on pilot plant scale. The pilot plant investigation of the process, which has consisted of more than 300 test runs on five different pilot plants, has been under way for several years. The scope of the work has included the development of satisfactory equipment, the investigation of process variables and charging stocks, and the solution of specific commercial design problems.

Because of the war it was necessary to begin the design and construction of commercial units before a comprehensive pilot plant program could be completed. Consequently, most of the early part of the pilot plant program was devoted to the solution of design problems.

Development of pilot plant equipment. The results of the early pilot plant tests in a plant that consisted essentially of a charge pump, a steel bomb equipped with a paddle mixer, a settler, a caustic scrubber for neutralizing dissolved HF, and a debutanizer were good enough to warrant further work. The next part of the program was devoted to the improvement of the pilot plant. One of the major problems in this connection was the development of a satisfactory contacting device. The contactor had to be so designed that thorough mixing of the hydrocarbon and HF phases could be obtained in a plant of a size corresponding to the limited supply of charging stock. It was found that a steel vessel fitted with a packed-shaft double impeller would best meet the requirements. One of the difficulties encountered with this mixer was the deterioration of the shaft packing through contact with the HF. This difficulty was overcome by passing the stirrer shaft through the top of the reactor, by lubricating the packing, and by bringing all of the hydrocarbon charge into the annular space around the shaft just below the packing, where it served as a protective flush. With this arrangement, runs of more than 30 days were made without packing failure.

Later in the pilot plant program a unit was constructed which included a Stratco contactor built on pilot plant scale. The first few runs showed that the conventional mechanical seal, flushed with charging stock, similar to that used on commercial contactors was not suitable for work on a pilot plant scale. The packing in the seal failed because the volume of charging stock was not sufficient to flush the HF away from the seal. This failure resulted in the leakage into the reactor of a large amount of the lubricating oil which was used to hold the faces of the seal together. This leakage was objectionable in that it resulted in contamination of the product. A modified type of seal was developed that reduced the seal oil leakage to between 1 and 2 cc. per hr. over an extended period of time.

Fig. 5



Problems concerned with process design. Three of the major problems in connection with plant process design that had to be solved on the pilot plants dealt with the recovery of dissolved acid in the alkylation products, the defluorination of the alkylation products, and the regeneration of the catalyst.

The importance of recovering the HF dissolved in the hydrocarbon stream leaving the catalyst settler is shown by the fact that the value of this dissolved HF amounts to about 3 cents a gallon of alkylate for a plant operating under the usual commercial conditions. Since HF and hydrocarbons are relatively immiscible and the HF is fairly volatile, it appeared that dissolved HF could be removed by fractionation from lower boiling hydrocarbons in a manner analogous to that used for the removal of dissolved water from light hydrocarbons.

In this type of separation the inorganic solute is driven upward in a countercurrent stripping column, and taken overhead in admixture with hydrocarbon solvent in sufficient concentration that the liquid resulting from condensation separates into two phases, the solvent phase being returned to the column. This system may be used in any separation of relatively immiscible liquids if the Henry's law constant of the solute is higher than the corresponding value for the solvent.

Approximate values of these constants may be readily determined from vapor pressure data for the pure components and solubility data, by consideration of a three-phase system at saturation. The partial pressure of each component from either liquid phase in such a system must be equal to that from the other liquid phase. In each case the partial pressure may be calculated by application of Raoult's law to the phase in which the component predominates.

Application of partial pressure data, determined by the above calculation, together with solubility data, to the phase which is predominantly hydrocarbon in a saturated isobutane-HF system indicates a Henry's law constant for the HF approximately ten times as high as that for isobutane.

In view of the indication from this

TUBE-TURN WELDING FITTINGS—RANGE OF SIZES

Type of Fitting	Description	Standard Weight	Extra Strong	Schedule 160	Double Extra Strong	Light Gauge Nominal Pipe Size	Light Gauge Iron Pipe Size
Elbows	90° Long Radius	½"-24"	¾"-24"	1"-12"	1"- 3"	4"-24"	3"-12"
Elbows	90° Short Radius	1"-30"	½"-30"				
Elbows	45° Long Radius	½"-30"	¾"-30"*	1"-12"	1"- 8"	4"-24"	3"-12"
Returns	180° Long Radius	½"-24"	1"-24"	1"-12"	3"- 8"	4"-24"	
Returns	180° Short Radius	1"-30"	1½"-30"				
Returns	180° Extra Long Radius	1"-2½"	1"-2½"	1"-12"	1"- 8"		
Tees	Straight	¾"-24"	¾"-24"	¾"-12"	1"- 8"		
Tees	Reducing Outlet	¾"-24"	¾"-24"		x⅜-12x10		
Reducers	Concentric & Eccentric	1x⅜-24x20	1x⅜-24x20		1"- 6"		
Caps		1"-24"	1"-24"				
Stub Ends	Lap Joint	1"-24"	1"-24"				
Nipples	Shaped, 90° to Header	1¼"-12"	1¼"-12"				
Nipples	Shaped, 45° to Header	1¼"-12"	1¼"-12"				
Saddles		2"-24"**	2"-24"**				
Laterals	Straight	1¼"-24"	1¼"-24"				
Laterals	Reducing-on-Run	1¼"-24"	1¼"-24"				
Crosses	Straight	¾"-24"	¾"-24"				
Rings	Welding	¾"-12"	¾"-12"				
Sleeves	Welding	2"-24"**					

*30" size short radius.

SUPER Tube-Turn 45° long radius elbows, 90° long radius elbows, and 180° long radius returns available in both Standard weight and Extra Strong in sizes from 3" to 12".

Tube-Turn welding fittings and flanges conform to applicable ASA and ASTM Standards. For further details please refer to Tube Turns catalog and data book No. 111.

**Since saddles and sleeves are used for external reinforcement only, they do not conform to iron pipe size thicknesses.

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	150 Lb.	300 Lb.	400 Lb.	600 Lb.	900 Lb.	1500 Lb.	2500 Lb.
Welding Neck	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"*	½"-24"	½"-24"
Slip-On	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"*	½"-24"	½"-24"
Lap Joint	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"	½"-24"	½"-24"
Threaded	½"-24"	½"-24"	½"-24"†	½"-24"	½"-24"*	½"-24"	½"-24"
Blind	¼"-24"	¼"- 4"		¼"-3½"			
Socket Type	¾"-24"	¾"-24"	¾"-24"†	¾"-24"	¾"-24"*	¾"-24"	¾"-12"
Reducing-threaded or slip-on		1"-24"	4"-12"	4"-12"	3"-12"	1"-12"	
Orifice—threaded		1"-24"					
Orifice—slip-on		1"-24"	4"-12"	1"-12"	3"-12"	1"-10"	
Orifice—welding neck		1"-24"	1"-10"	1"-10"	1"-10"	1"-10"	
Long Welding Neck	1"-24"						

†Dimensions on sizes thru 3½" same as for 600 lb. flanges.
*Dimensions on sizes thru 2½" same as for 1500 lb. flanges.

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calculation that such a means of separation would be operable, a stripping column based on this principle was constructed and installed in the pilot plant. Tests on this column demonstrated that the HF could be stripped easily from the settler effluent.

Because the presence of combined fluorine in the products of alkylation is objectionable, a method of removal had to be developed. Preliminary testing of many defluorinating agents in the laboratory was followed by more extensive testing of the promising materials on the pilot plants. The data sought were the life of the defluorinating agent and the relationship between space velocity, temperature, and per cent of defluorination. As a result of this work it was decided that bauxite should be used as the defluorinating material in the first commercial units.

Although bauxite was sufficiently good to warrant its incorporation in the early plants, it had certain disadvantages. One of these was that it combined with the fluorine which it removed from the alkylation products, so that it caused appreciable HF consumption. Another disadvantage was the necessity for the periodic replacement and disposal of the spent bauxite. A better defluorinating agent has been found, however, which catalytically decomposes the alkyl fluorides into HF and olefins. This new catalyst will be used in such a manner that the liberated HF will be returned to the reaction zone. Thus, its use will reduce HF consumption and eliminate an operating inconvenience.

One of the distinct features of the HF alkylation process is the ease with which the tarry material that gradually accumulates in the catalyst phase may be removed. A method of regeneration was first discovered in the laboratories, where it was found that simple distillation restored the activity of used catalyst. Pilot-plant work in connection with acid regeneration was primarily directed towards obtaining design data.

Studies of the process variables. A considerable amount of data with respect to the effects of the feed-stock composition and process variables was obtained during the early part of the pilot plant program. The olefins that were investigated for alkylating isobutane included various butylenes, propylene, amylenes, polymers, gasoline fractions, and mixtures of the foregoing olefin hydrocarbons. The effects of impurities, such as butadiene, sulphur, and water, were studied. Tests also were made in which isopentane was used as the isoparaffin. Operating variables, including the isoparaffin-olefin ratio, catalyst activity, space velocities, tempera-

ture, and degree of mixing, were studied to determine their effects upon the yield of aviation alkylate, octane number, HF consumption, and regeneration requirements. These investigations are still under way.

Chemistry of the alkylation process. Much of the experimental work was directed toward developing the chemistry of the process with a view to orienting the further pilot plant work and commercial plant design. The reactions involved were found to be complex, since HF is a catalyst for a variety of different reactions. It can be shown that little or no reaction takes place in the hydrocarbon phase, since for a given feed rate relative to catalyst volume, changing the hydrocarbon residence time does not appreciably alter the overall results. The olefins apparently combine rapidly with the hydrogen fluoride and remain in the catalyst phase until converted into some other material through chemical reaction. Isoparaffins are slightly soluble in HF. The paraffinic products of reaction are also of limited solubility and may be readily extracted from the catalyst phase by contact with a hydrocarbon stream.

The principal reactions occurring in the reaction zone are apparently as follows:

(1) Direct interaction of an olefin and an isoparaffin, either of which may be charged as such or may be the result of previous reactions.

(2) De-alkylation of paraffins of high molecular weight.

(3) Polymerization of olefins to form olefins of higher molecular weight.

(4) Depolymerization reactions.

(5) Hydrogen transfer reactions between olefins to form saturated hydrocarbons and tars of low hydrogen content.

(6) Hydrogen transfer reactions between paraffins and olefins to form a paraffin corresponding to the olefin and an olefin corresponding to the paraffin.

(7) Probably by the above reactions, net isomerization, particularly of the alkylate product, may occur.

A number of reactions take place, and a variety of products may be made by changing the balance of these reactions. The most desirable products are those of the direct combination of the olefin and the isoparaffin feeds, and conditions should be so chosen as to favor such a reaction within the limits of commercial practicability. The means of adjusting the balance between reactions lies in the control of the concentrations of the various reactants and reaction products.

The undesirable reactions between olefins may be minimized by maintaining a low concentration of organic fluorides in the catalyst phase; this condition may be brought about by the use of a large catalyst pool relative to the charge rate. Therefore, units should be designed and operated to maintain a relatively large volume of catalyst in the reaction zone.

The desired reaction of primary alkylation is favored by a high concentration of isobutane and a low concentration of alkylate in the catalyst phase. The chemical reactions tend to decrease the concentration of isobutane in the catalyst phase and to increase the concentration of alkylate in the catalyst phase. The recycling of isobutane increases isobutane concentration and decreases alkylate concentration in the hydrocarbon phase and, consequently, increases isobutane concentration and decreases alkylate concentration in the catalyst phase when other conditions are constant. Increasing intimacy of contact also increases isobutane concentration and decreases alkylate concentration in the catalyst phase by providing more interfacial surface for material transfer. The latter effect diminshes as physical equilibrium is approached. Thus, recycling isobutane, affording greater intimacy of contact, results in a cleaner reaction.

Locally, at a region in the reaction zone, the concentration of isobutane may be too low and the concentration of olefin too high in the catalyst phase, if the internal circulation rate of the catalyst phase past the point of olefin injection is too low. Consequently, increasing the internal recirculation rate of the reaction mixture, including the catalyst phase, favors the desired reaction.

Another process variable which has been found to be useful in controlling the reaction is the concentration of HF in the catalyst phase. Tars from hydrogen transfer reactions accumulate in the catalyst phase until removed by distillation. These tars alter both the solubility and the reaction characteristics of the catalyst; therefore, the amount of such materials has an influence on the type of reaction obtained. It has been determined experimentally that there is an optimum concentration of these materials.

Temperature has been found to have little effect on the direction of the reaction in the range normally encountered.

Pressure under which the reaction occurs should be sufficient to maintain the reactants and catalyst in the liquid phase.

A small portion of the total organic fluorides present in the reaction system at any time is in the hydrocarbon phase and is carried out of the reaction system with the hydrocarbons. It is desirable to employ operating conditions such that the amount of this material in the hydrocarbon phase is kept at a minimum in order to conserve HF. Since the amount in the hydrocarbon phase is a function of the concentration in the catalyst phase, it follows that conditions which prevent the interaction between olefins, such as a relatively large catalyst pool, also minimize the loss of organic fluorides. The concentration of organic fluorides in the hydrocarbon phase may be kept low by maintaining a relatively high concentration of HF in the catalyst phase.

Testing of material and equipment. Many materials were tested statically in the laboratory for resistance to corrosion both in anhydrous HF and in a constant-boiling mixture of HF and water. The more promising materials were tested dynamically in commercial equipment in which a mixture of equal portions of anhydrous HF and butanes was circulated by means of a standard single-stage overhanging-type centrifugal pump through a system containing various types of valves, flow meters, control valves, and other equipment. Satisfactory available materials were found for various services.

Extensive experimental work on packings for pumps and valves, lubricants for plug cocks, substitutes for conventional gauge glasses, and many other mechanical features and techniques was necessary in order to obtain the engineering information required for the design of a commercial plant.

Special features in mechanical design. Previous to the development of the HF alkylation process there had been no installation in which anhydrous HF had been pumped in large quantities. Small pumps had been used for loading and unloading tank cars; but losses due to leaks were relatively high, and the life of the pumps was short. The proposed designs in some cases involved the circulation in the reactor systems of quantities up to 300,000 gal. per min. and the pumping of external catalyst streams up to 900 gal. per min. into reactor systems containing approximately 20,000 gal. of HF. Leaks could not be tolerated in a large plant because of the hazards involved and the value of the material. Since concentrated HF attacks pump packings, it was necessary to make special provision for a leakproof pumping system. Many similar changes from standard designs for hydrocarbon and chemical manufacture were required in instruments,

valves, piping, and other parts of the plant. Because of wartime conditions, it was necessary to adopt, as far as possible, standard equipment with a minimum of modification. Special means of combating contamination of the atmosphere and pollution of surface water had to be devised.

Reactor equipment. Three basic requirements had to be met by the equipment in the reaction zone. It had to provide intimate contact between phases, ample volume to maintain a satisfactory reaction time, and means for removing the heat of reaction. Standard Stratco contactors with built-in cooling bundles were selected, and only slight modification was necessary to meet these requirements. These contactors, one of which is shown in Fig. 2, are built of rolled carbon steel flanges and shell with cast steel bottom heads and mixing impellers. The contactor most commonly used has a volume of 4900 gal. and an impeller driven by a 250-hp. unit. Leakage along the impeller shaft is prevented by a mechanical seal.

Special pumps for HF service. Satisfactory methods of pumping and metering the catalyst phase had to be developed in connection with the investigations concerning regeneration, because the quantities handled were below the practical range of a centrifugal pump.

A mercury surge pump was developed for this service. A conventional plunger type of pump is connected through a "U" bend to ball check valves. Mercury is placed in the "U" bend, and a light oil is maintained between the mercury and the plunger of the pump. The HF in the opposite leg is moved by the mercury. A commercial lubricator is connected to the driving mechanism of the pump and continuously injects a small amount of oil to offset leakage.

Instruments. The problems of the design engineer were simplified somewhat by recent developments in instruments, such as wide-range level controls, torque-tube transmission, aneroid differential instruments, and remote electric flow meters. Such instruments have made possible the measurement, recording, and controlling of flows and levels in HF service without the possibility of leakage that might be expected through conventional stuffing-boxes. Hardened carbon steel parts were substituted for the critical alloys usually employed for trim.

Because the solubility of HF in hydrocarbon varies with temperature, meter lines were purged to avoid precipitation which might be caused by change in temperature. An exhauster connection was also provided to facilitate preparing the instrument for removal from service. Fig. 3 illustrates a typical HF hydrocarbon flow meter installation.

Standard pressure gauges were modified for HF service by incorporating a seamless steel bourdon tube welded or silver brazed at the tip and in the socket.

Skin-type thermocouples were used for temperature indication to minimize connections into equipment containing HF. Fig. 4 illustrates a typical skin couple.

For reasons of safety all instruments that contained HF were mounted locally, and either air or electricity was employed for transmission to, or remote control from, the main instrument board.

Pressure-relief systems. A closed relief system, through which all relief valves in HF service discharge, carries the vapors to a remote scrubber where they are neutralized before venting. The relief valves in HF service have special trim and are protected by a corrosion-resisting rupture disk. Fig. 5 illustrates a typical relief valve installation. The connection between the safety head and the relief valve is normally open to the relief header; it is closed only for the purpose of detecting a leak in the rupture disk. By closing the valve in the connection and by opening the valve against the pressure gauge, one can detect whether or not the safety head has developed a pinhole leak.

In addition to the regular safety valves, there is an auxiliary relief system, which is set to operate at a pressure 15 to 20 lb. per sq. in. below the relief valve setting. This blowdown system consists of a closed tank that is capable of receiving the entire contents of the contactors and acid settler. Each contactor and acid settler is equipped with a hydraulically operated drop-out valve, which is automatically operated. It may also be remotely controlled from the instrument board, or manually operated.

Drain and exhauster system. A system whereby HF and hydrocarbons can be purged from any part of the system by evacuation was substituted for the conventional vents and drains. The exhauster clusters are usually limited to from four to eight process connections so that valve leaks can be more easily located. A hydrocarbon seal prevents leakage of HF between the process equipment and the exhauster header.

Utilities. The utilities are an important factor in the economical operation of an alkylation plant, and some changes were made from the ordinary design in order to utilize water and steam in the most economical manner. In general, the entire volume of cooling water that is required in the unit is passed through the cooling bundles in the contactors, where the rise in temperatures is usually about 1½° F. The water is then taken to the low-temperature-level condensers and coolers, and is finally used in the higher-temperature-level equipment. In this manner it is possible to economize on condenser and cooler surface. The water is usually returned to the cooling tower at about 115° F., so that satisfactory cooling tower efficiency results. Recording pH instruments were installed for detecting any HF leaks into the water system.

The bottom temperatures on the various fractionation columns vary from 175 to 375° F., and, for the greatest economy, it was found that, if all of the steam was supplied at 400 or 425 lb. per sq. in. and 50 or 75° F. superheat, most of the power required for pumping and circulating could be taken out of the steam prior to its use in low-temperature reboiler service. That is, turbines will operate on steam at a pressure of 400 lb. per sq. in. gauge on the governor and exhaust at a pressure of 45 lb. per sq. in. The exhaust steam will be at a satisfactory temperature for reboiling the low-temperature towers. Other turbines discharging at 150 lb. per sq. in. supply steam to the intermediate-level reboilers.

Commercial results. Several commercial HF alkylation plants are in operation, and a number of others will be completed in the near future. The results obtained have come up to the expectations based on pilot plant data. The aviation alkylate has an octane number of about 93 *A.S.T.M.* The fluorine content of the aviation alkylate has consistently been less than five parts per million. The mechanical troubles encountered have not been greater than those experienced normally in oil refinery equipment.

The HF alkylation process is typical of the war developments of the petroleum and chemical industry. Through the cooperation of research workers, development and design engineers, HF manufacturers, and equipment suppliers, it has been possible to bring a new process into commercial operation in time to aid in meeting the serious problem of supplying the wartime aviation gasoline requirements.

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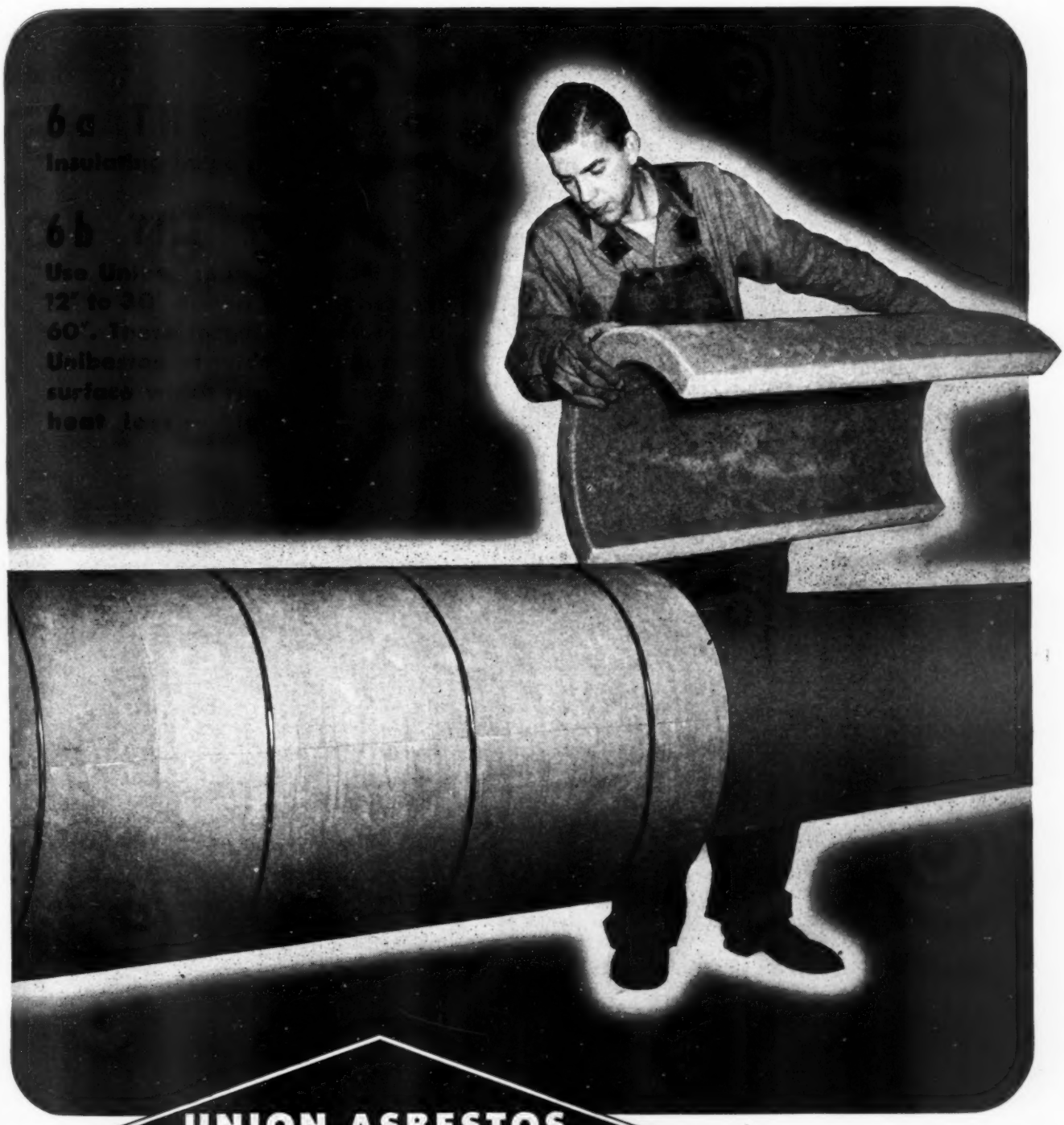
This is the 6TH *in a series of messages*

DEALING WITH THE PROBLEMS IN HEAT INSULATION FACED BY ENGINEERS AND SOLVED BY USING UNIBESTOS



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Refinery Corrosion Problems*

By IVY M. PARKER
J. S. Abercrombie Company

FOR economic reasons the solution of any corrosion problem pays dividends. During war time the conservation of materials is equally important.

Refinery corrosion problems begin when the crude enters the refinery and do not cease until the products line leaves. In the Gulf Coast area we have four corrosion problems: (1) Oil, (2) atmosphere, (3) soil, and (4) water. I propose to discuss briefly the corrosion of steel in contact with the first and last, namely oil and water.

The corrosion problems associated with the metals in contact with the oil may be classified into two groups—those associated with sweet crudes and those with sour crudes. The problems associated with sweet crude are very minor when compared with those encountered with sour crudes. The sour crude problems may be classed as those associated with low (below 500°F.) temperatures as in crude units, as contrasted to high temperature corrosion as in cracking unit furnace tubes. This last problem has been attacked mainly by installing alloy metal tubes that will withstand the conditions encountered.

Corrosion problems are very specific and no general remedies can be given. Some conditions with which I am familiar along with steps that have been taken in an attempt to improve them are cited.

I shall touch very briefly upon crude oil pipe line corrosion as my experience with this problem has been very limited. A few sections of line that had been removed because of failure have been examined. Here the internal corrosion appeared to be more severe on the bottom side indicating some relation to the moisture content. I have assisted Derk Holysten of Shell Oil Company, Inc., in examining the white material resulting from electrolytic corrosion of pipe lines to identify ferrous iron probably present as hydroxide. This problem of electrolytic corrosion of pipe lines is a vital one in the refinery setup.

Following the crude into the refinery, it is a well known fact that steel tanks suffer greatly in the presence of sour crudes or unsweetened sour products. Tank bottom corrosion arises from attack from water settling from the crude (the severity usually depending upon the pH of the water) and from scale, containing sulphide and free sulphur, falling from the roof to the floor. These scale particles apparently set up highly anodic points and produce severe pitting. The roof and top ring of the tank suffer severely from the damp sulphide atmosphere containing some air. Free sulphur is liberated and deposited to produce specific anodic areas and pitting. As a rule very little corrosion takes place in the sweet crude storage tanks provided the settled water is not acid. Sweet crudes appear to be acid mainly when the wells have been acidized and the crude improperly washed. Our friend or enemy magnesium chloride is usually associated with sour crudes. Gunnite has proved a valuable tool in reclaiming rapidly failing tanks. The life of both roofs and bottoms have been extended greatly by applying this special cement or concrete.

Corrosion in the refinery crude unit is most pronounced in condensers, coolers, and rundown lines. This problem is always associated with hydrochloric acid production, either from acid present in the crude or produced by hydrolysis of magnesium chloride, and/or sulphide production with the combination being worse than either alone. The point of attack in these instances is definitely associated with the initial condensation of moisture.

This problem has been attacked by two methods: (1) Desalting the crude, and (2) neutralizing the acid constituents at the point of condensation. The first when effectively carried out materially reduces the corrosion. The second usually employing caustic or ammonia with or without flushing with water is of great benefit but does not solve the problem. Ammonia has gained preference over caustic because less difficulty is experienced with salt choking. In prewar days the general practice was to construct condensers and coolers of admiralty metal bundles with steel or cast-iron shells. Then the problem was to effectively neutralize the acid condensate as formed. The success of the operation depended upon a balance between the proper neutralization of the acid without undue attack of the admiralty by the ammonia. By custom the control has been to adjust the pH of the water drawn off to 7.5 to 8.0. This did not solve the problem because frequent replacement of condenser bundles, steel shells, and rundown lines were still necessary.

With the material shortage experienced in recent months, it has been necessary to replace the admiralty bundles with steel. In one such case the ammonia injection was increased to raise the pH of the condensate to between 8.5 and 9.0. The steel tube bundles lasted only 3 to 6 months. Admiralty tubes under similar conditions except pH of 7.5 lasted 6 to 12 months.

It has been proposed that organic chromium compounds could be injected into the vapor line above the condensation point, which would inhibit the steel against attack. An attempt to try this material was abandoned because of mechanical difficulties.

The corrosion in the products pipe lines has been proved to be associated with the water accompanying the oil. The problem has been attacked by reducing the quantity of water to a minimum, applying scrapers periodically to remove products of corrosion, and by adding water soluble corrosion inhibitors. Of these sodium nitrate has given excellent results.

Corrosion is also an important problem in the cooling water system of the refinery. As in all other types of corrosion we have anodic and cathodic areas with the metal going into solution at the anode. In neutral or slightly alkaline medium the corrosion products form a barnicle or tubercle covering the anodic area. Thus, there is the problem of loss of metal coupled with reduction in capacity.

The average refinery cooling water system consists of the makeup source, heat exchangers and cooling tower with the water circulating through the tower every 15 to 30 min. Each time the water passes over the tower, it becomes virtually saturated with air besides picking up corrosive gases such as CO_2, H_2S and SO_2.

Some of the factors that contribute to water side corrosion are dissolved oxygen, oil, sulphide and composition of metals. The principal means of combating it are the use of water soluble rust inhibitors, natural or added. Deaeration has been used effectively and cathodic protection has been applied with considerable success in some cases.

Fundamentally our cooling water corrosion involves the following reactions:

Anodic

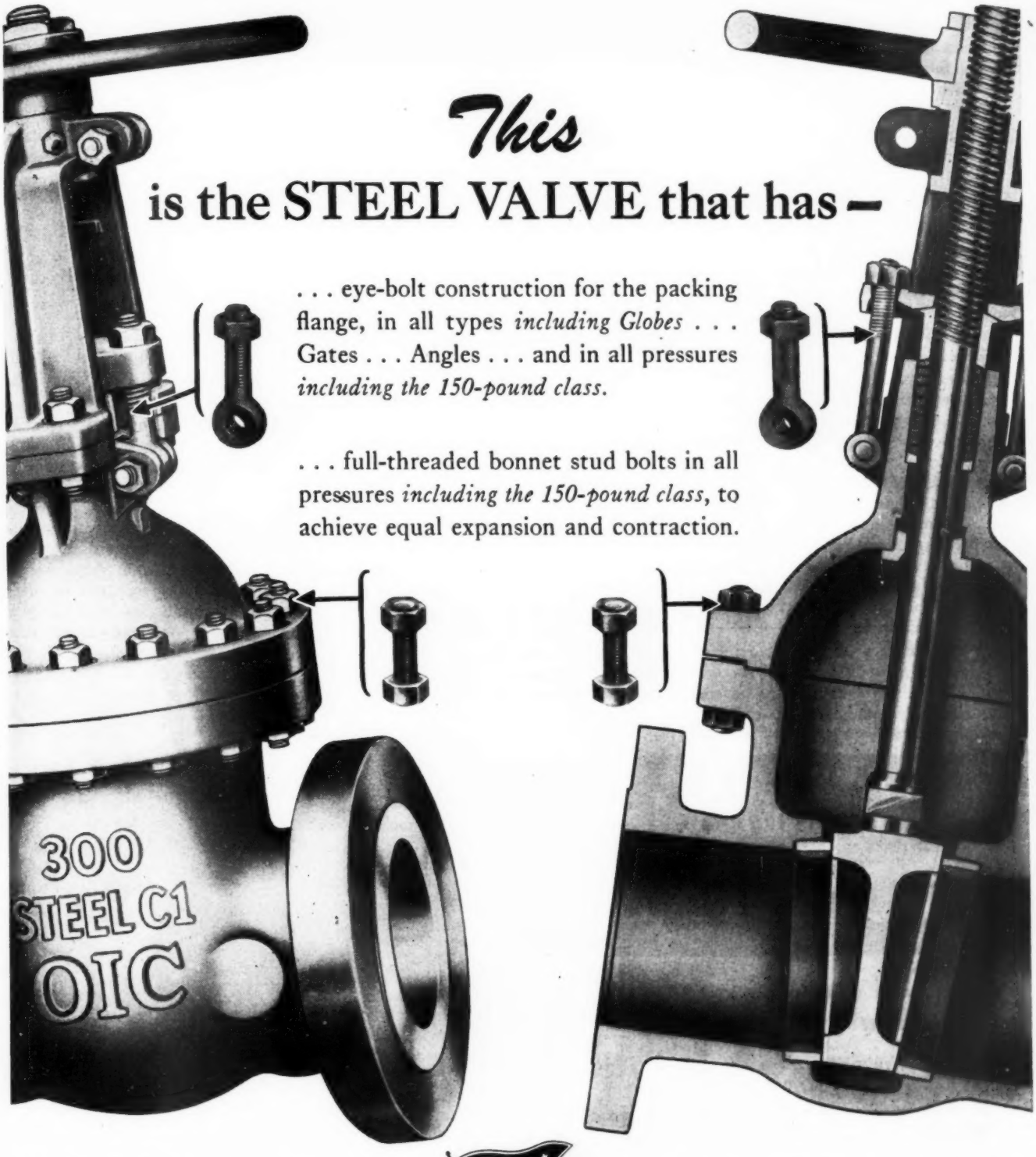
$$Fe^{\circ} - 2\,(-) = Fe^{2+}$$

Cathodic

$$O_2 + 2\,H_2O + 4\,(-) = 4\,OH^-$$

As indicated by the reactions, the process is under cathodic control with an alkyline condition existing at the cathode area and the iron going into solution at the anodic area. This reaction may be inhibited by restricting the oxygen content as in deaeration or by covering the cathodic area with a film that is not permeable to oxygen. It may also be inhibited by restricting the rate of reaction at the anode. Normally the corrosion product is a complex iron oxide that is permeable to the passage of chloride ions and water and does

*Presented before National Association of Corrosion Engineers, Houston, Texas, April 10-12, 1944.



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not materially stifle the reaction. In addition an area of low oxygen concentration is established, which in conjunction with the air saturated cooling water sets up ideal conditions for oxygen concentration cells. Thus the intensity of the corrosion increases.

You are probably familiar with Evans classification of inhibitors as safe and dangerous which in reactions under cathodic control apply to cathodic and anodic inhibitors. He defines as cathodic those inhibitors which stifle the corrosion by limiting the cathodic area thereby decreasing the intensity of corrosion without reducing the area affected. The anodic inhibitor initially stifles the anodic area without reducing the intensity and will temporarily increase tendency to pittng. If sufficient inhibitor is applied the latter condition will continue to exist. For this reason Evans classes the anodic inhibitor as dangerous. Chromates and silicates fall into this class in very soft waters. In hard waters silicates appear to have some cathodic effect as well as anodic. Controlled calcium carbonate precipitation is definitely cathodic in action.

My experience with water corrosion is limited to three types of water: aerated soft high bicarbonate, unaerated soft bicarbonate, and soft low alkalinity water, the greater portion being with the soft bicarbonate water. Typical analyses of these waters are as follows:

	1	2	3
SiO_2, p.p.m.	12	22	10
R_2O_3, p.p.m.	1	3	1
Calcium, p.p.m.	7	7	10
Magnesium, p.p.m.	2	31	5
Sodium, p.p.m.	169	—	37
Carbonate, p.p.m.	0	0	0
Bicarbonate, p.p.m.	352	278	55
Chloride, p.p.m.	73	1360	45
Sulphate, p.p.m.	11	0	14
Organic material, p.p.m.	—	519	—
Dissolved solids, *p.p.m.	451	2108	148
pH	8.0	8.0	8.0

*Calc. with bicarbonate converted to carbonate.

A plant started up on the soft bicarbonate water shown in analysis No. 1 did not show serious corrosion until after sodium hexametaphosphate had been introduced as a scale inhibitor. It was assumed that the phosphate brought about the removal of the natural inhibitor, $CaCO_3$, present in the water Abandonment of the hexametaphosphate for a period of 6 months did not appear to reduce the corrosion rate and the scaling in the hot sections made it necessary to reapply the phosphate. Two corrosion inhibitors were applied along with the phosphate with considerable success. In systems where there was a build up of solids due to concentration the D. W. Haering Company Quachrom was used in concentrations of 35 to 50 p.p.m. with very good results. In systems where less than three concentrations of solids was obtained sufficient 40° Bé sodium silicate was added to raise the normal SiO_2 content 10 to 20 p.p.m. The results were excellent in the oil free systems. In systems containing oil and sulphide there was great improvement but the results were still none too good.

The water represented by analysis No. 2 was pumped from the well directly through the units and therefore was not aerated. It contained considerable dissolved gases and some CO_2. The corrosion from this water was only tube-end corrosion and appeared to be associated with turbulence. The tube ends were protected by applying paint.

The water represented by analysis No. 3 was lime softened water and was introduced into a cooling system containing considerable oil. The loss of water from the system was great enough to prevent more than 1.5 concentration of solids. Severe corrosion set up in the system in a short time. Application of sodium silicate was started to effect a decrease in number of active areas but at present serious pitting is still taking place. The next steps to be taken are removal of the oil and elimination of some of the water waste.

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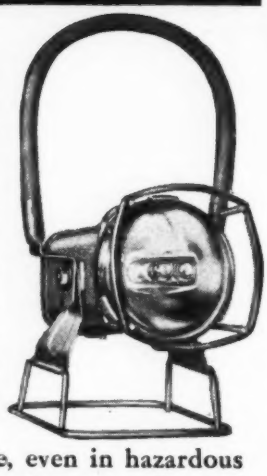

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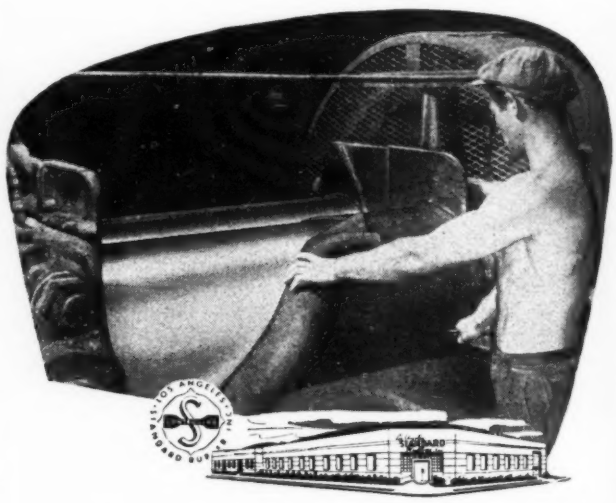

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Viscosities of Natural Gases*

By LEO B. BICHER, JR., and DONALD L. KATZ
University of Michigan

THE viscosity of a natural gas is required whenever calculations are made of the pressure drop that occurs while the gas flows through pipes or porous media. Methods of predicting the viscosities of gases at the present operating pressures are not available. This paper presents a simple method of predicting the viscosity of a natural gas in the single-phase region from its molecular weight, temperature, and pressure.

Viscosity of methane-propane mixtures. The viscosity of methane, propane, and four of their binary mixtures, 20, 40, 60, and 80 mol per cent, have been determined for pressures from 400 to 5000 lb. per sq. in. and temperatures from 77° to 437° F., with an experimental accuracy of 3.2 per cent.[2] The apparatus used in the investigation was a modification of that employed in previous studies[8,14] on the viscosity of normal paraffin hydrocarbons. It consists of a viscosimeter of the rolling-ball, inclined-tube type,[5,6,7] with auxiliary equipment for making up and charging binary mixtures into the viscosimeter.[2] The viscosity data on the methane-propane mixtures have been plotted as a function of molecular weight with lines of constant pressure, charts of constant temperature in Figs. 1 to 3. These charts are extrapolated at temperatures below 77° F. and at pressures above 5000 lb. per sq. in.

Prediction of viscosity from molecular weight of a natural gas. At atmospheric pressure the viscosity of light hydrocarbon gases increased with increased temperature, contrary to the change of viscosity of liquids with temperature. The atmospheric viscosities of the normal paraffin hydrocarbons have been determined by several investigators[3,4,9,10,12,15,16,17,19] and are plotted in Fig. 4 as a function of molecular weight, with extrapolation to 896° F. and to 220 molecular weight. Data for isopentane and normal pentane show less than 2 per cent difference in viscosity, indicating that Fig. 4 can be used for isomeric paraffin hydrocarbons with an accuracy of approximately 2 per cent. Trautz and Sorg[17] determined the atmospheric viscosities of methane-propane mixtures and showed that they are proportional to the molecular weight. The viscosities of these mixtures calculated from Fig. 4 represent the experimental data with an average deviation of 0.44 per cent, as tabulated in Table 1, indicating that Fig. 4 can be used for obtaining the atmospheric viscosities of light paraffin hydrocarbon mixtures such as natural gases. Berwald and Johnson[1] determined the atmospheric viscosities of natural gases containing various amounts of nitrogen. Their data are represented by Fig. 4 with an average deviation of about 3.5 per cent, comparable with their experimental accuracy, for gases containing less than 7 per cent of nitrogen. For gases containing higher percentages of nitrogen, a molecular average of the viscosity for nitrogen-free gas as read from Fig. 4 and for pure nitrogen gave satisfactory agreement with the experimental data.

Since the viscosity of light paraffin hydrocarbon mixtures is a function of molecular weight at atmospheric pressure, it might be expected that the same relationship would hold for higher pressures. To test the applicability of Figs. 1 to 3 for predicting the viscosities under pressure of light hydrocarbon mixtures such as natural gases from the molecular weights or gravities of the gases, a comparison is made between the predicted viscosities and the experimental values reported for natural gases in Table 1. The predicted viscosities compare with the reported values with an average deviation of 5.8 per cent. This accuracy is comparable with the experimental accuracy of "approximately 5 per cent" reported by Sage and Lacey.[13]

The two-phase region indicated in Figs. 1 to 3 is the two-phase region for the methane-propane system. It is known that the two-phase region is a function of the concentration of the constituents in the gas as well as of the molecular weight. For this reason, and because the physical properties of fluids are known to change rapidly near the critical region, Figs. 1 to 3 should not be used for predicting the viscosity of a gas near its critical region, or at a temperature and pressure where two phases exist.

The methane-propane data may be correlated on the basis of molecular weight, pseudocritical temperature, and pseudo-critical pressure.[2] The prediction of the viscosity of a natural gas by this relationship requires the analysis of the gas from which the pseudo-criticals may be computed. Although this correlation based on pseudo-critical temperature and pressure has advantages for predicting viscosities of miscellaneous hydrocarbons, especially in the neighborhood of the two-phase re-

TABLE 1
Comparison of calculated viscosities with reported values

Gases investigated	Mol per cent CH_4	Molecular weight	Temperature, °F.	Pressure, lb. per sq. in.	Viscosity, micropoises		Percentage of error
					Calcd.	Exptl.	
Trautz and Sorg[17] CH_4-C_3H_8 mixture	63.16	26.4	32	14.7	88.3	88.9	− 0.68
			104	14.7	100.1	100.8	− 0.70
			248	14.7	122.2	123.6	− 1.13
			392	14.7	143.5	144.1	− 0.42
			464	14.7	153.3	153.2	+ 0.07
CH_4-C_3H_8 mixture	36.17	33.9	32	14.7	82.0	82.1	− 0.12
			104	14.7	93.2	93.4	− 0.21
			248	14.7	114.7	115.3	− 0.52
			392	14.7	135.2	135.5	− 0.22
			464	14.7	144.6	144.3	+ 0.21
CH_4-C_3H_8 mixture	16.59	39.4	32	14.7	77.8	77.5	+ 0.39
			104	14.7	88.6	88.4	+ 0.23
			248	14.7	109.8	109.2	+ 0.55
			392	14.7	129.8	129.0	+ 0.62
			464	14.7	139.2	138.5	+ 0.52
Sage and Lacey[13] Lean natural gas	83.19	20.4	100	500	122	133	− 8.3
				1,500	163	180	− 9.5
				2,500	214	219	− 2.3
			160	500	129	136	− 5.2
				1,500	161	172	− 6.4
				2,500	205	200	+ 2.0
			200	500	133	145	− 8.3
				1,500	160	174	− 8.1
				2,500	192	192	± 0.0
Rich natural gas	69.74	25.0	160	1,000	146	150	− 2.6
				1,500	174	170	+ 2.4
				2,000	203	191	+ 6.3
			200	1,000	144	146	− 1.4
				1,500	166	157	+ 5.7
				2,000	183	169	+ 8.3
Berwald and Johnson[1] Natural gas No. 2	98.4	16.2	60	103.2	108	103	+ 4.9
				304.6	113	103	+ 9.7
				499.8	118	103	+14.6

*Presented before American Institute of Mining and Metallurgical Engineers, New York City, February, 1943.

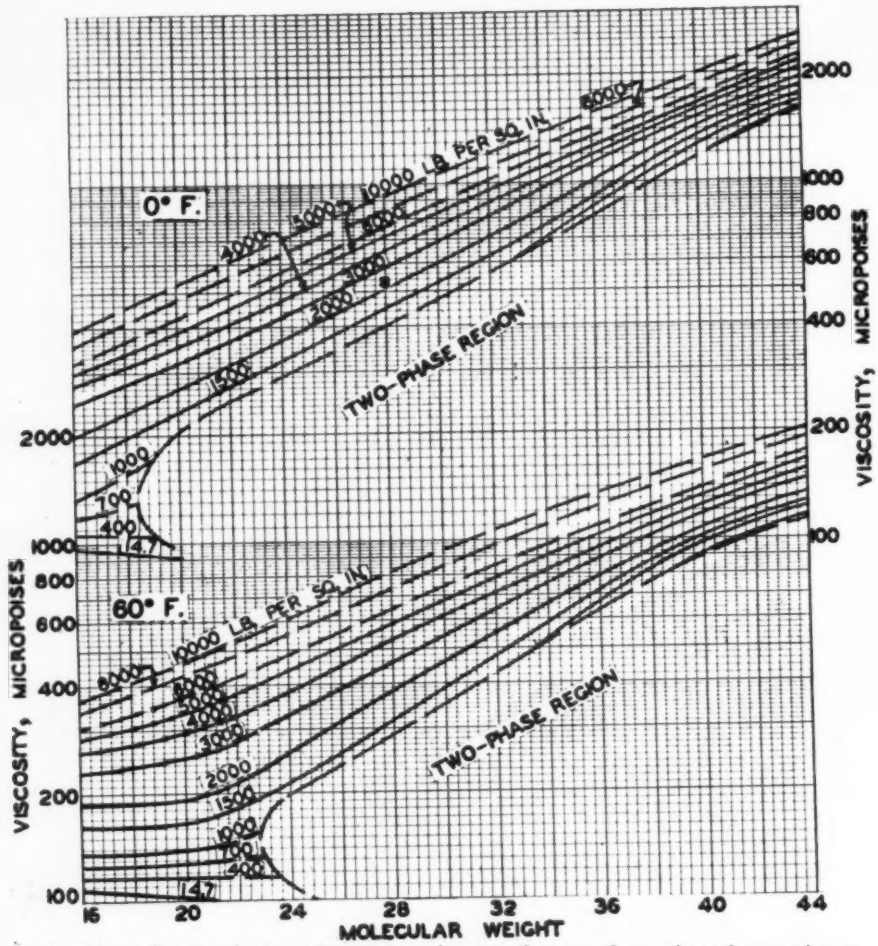

Fig. 1. Chart for predicting viscosities of natural gases from data for methane-propane mixtures

gion, it does not reproduce the data on natural gases any more closely than the simple molecular-weight plots.

Example calculation. For purposes of illustration, the viscosity of the lean natural gas reported by Sage and Lacey[13] will be calculated from its molecular weight, at 160° F. and 2500 lb. per sq. in. In this case, the analysis is given but a measured gas gravity (air = 1.0) would have been sufficient.

Calculated average molecular weight = 20.42

Viscosity at 100° F., 2500 lb. per sq. in. = 214 micropoises (from Fig. 2)

Viscosity at 200° F., 2500 lb. per sq. in. = 192 micropoises (from Fig. 2)

Assuming straight-line interpolation between the temperature plots, the viscosity of the lean natural gas at 160 °F. and 2500 lb. per sq. in. is:

$$214 - \frac{160 - 100}{200 - 100}(214 - 192)$$

$$= 205 \text{ micropoises}$$

The corresponding experimental value reported by Sage and Lacey is 200 micropoises.

If the viscosity is changing rapidly with temperature, the viscosities at any given pressure and molecular weight could be plotted as a function of temperature, as a means of interpolation.

Gases containing nitrogen. Figs. 1, 2 and 3 are based on methane-propane mixtures without the presence of nonparaffin hyrocarbons. Although the relationships presented may apply for unsaturated hydrocarbons, the viscosity of gases containing more than about 5 per cent nitrogen should not be obtained by using Figs. 1 to 3 directly. Since at atmospheric pressure the molal average viscosity of nitrogen and the nitrogen-free hydrocarbon gas reproduces the experimental value, a similar procedure for gases under pressure should be the best approximation now available. Table 2 presents viscosity values for nitrogen interpolated and extrapolated from literature [11,19] data at 25°, 50°, and 75° C. for pressures to 10,000 pounds.

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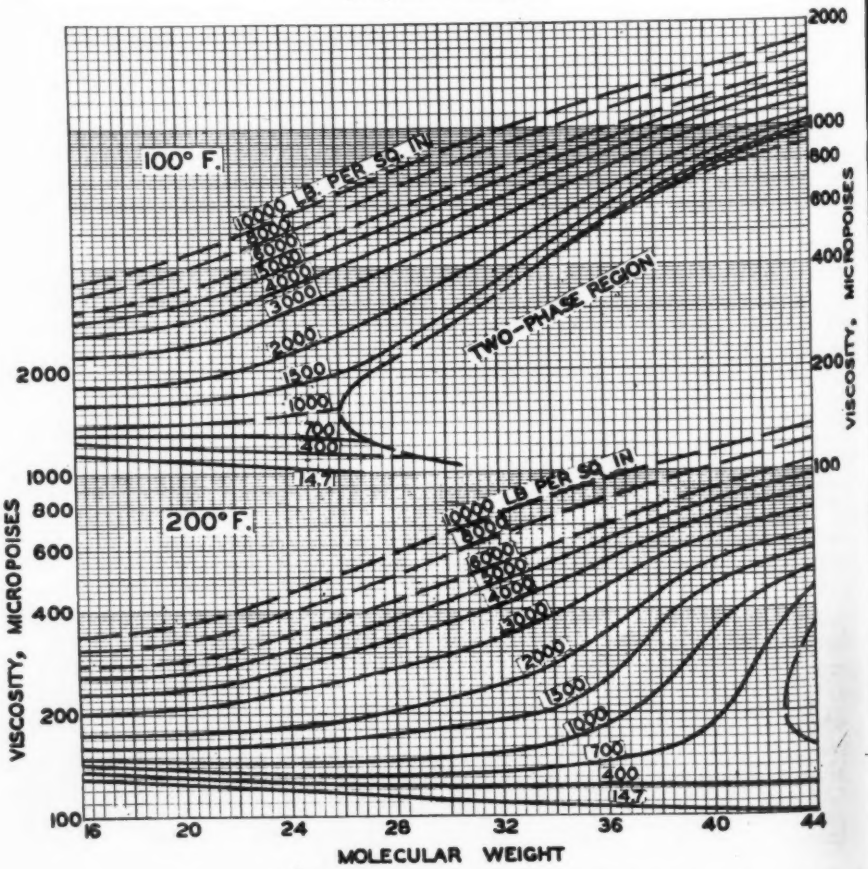
Fig. 2. Chart for predicting viscosities of natural gases from data for methane-propane mixtures



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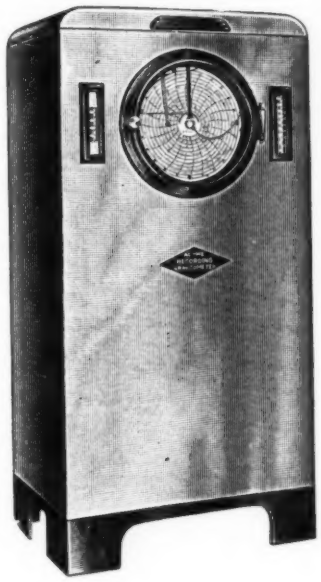

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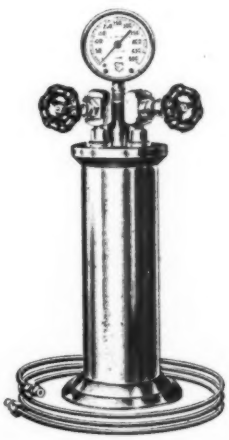

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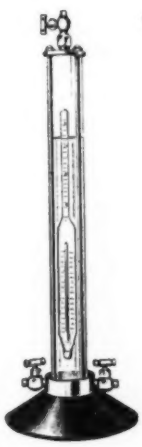

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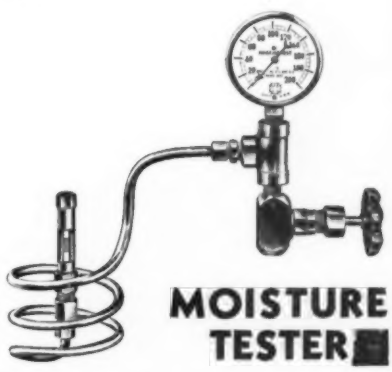

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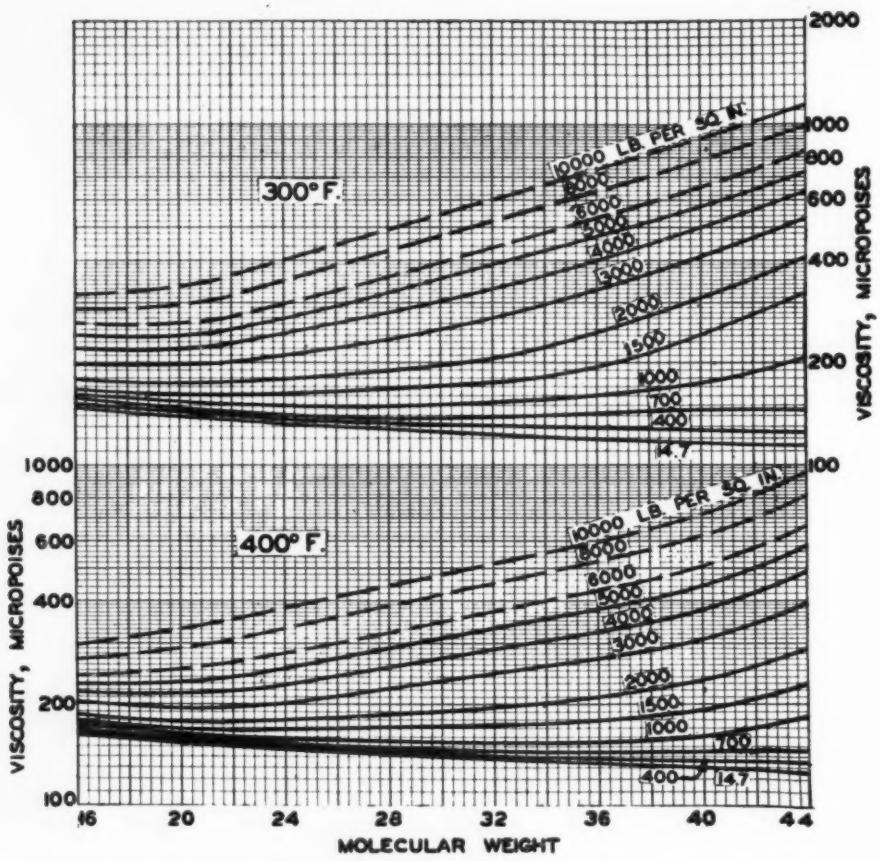

Fig. 3. Chart for predicting viscosities of natural gases from data for methane-propane mixtures

TABLE 2
The viscosity of nitrogen

Pressure, lb. per sq. in. abs.	Temperature, °F.				
	0	60	100	200	300
	Viscosity, micropoises				
14.7	156	172	182	206	227
500	163	179	188	213	234
1,000	176	188	196	217	238
2,000	203	208	213	229	247
3,000	234	234	234	242	256
4,000	259	257	257	261	268
6,000	328	315	308	299	295
8,000		373	358	337	323
10,000		433	405	377	351

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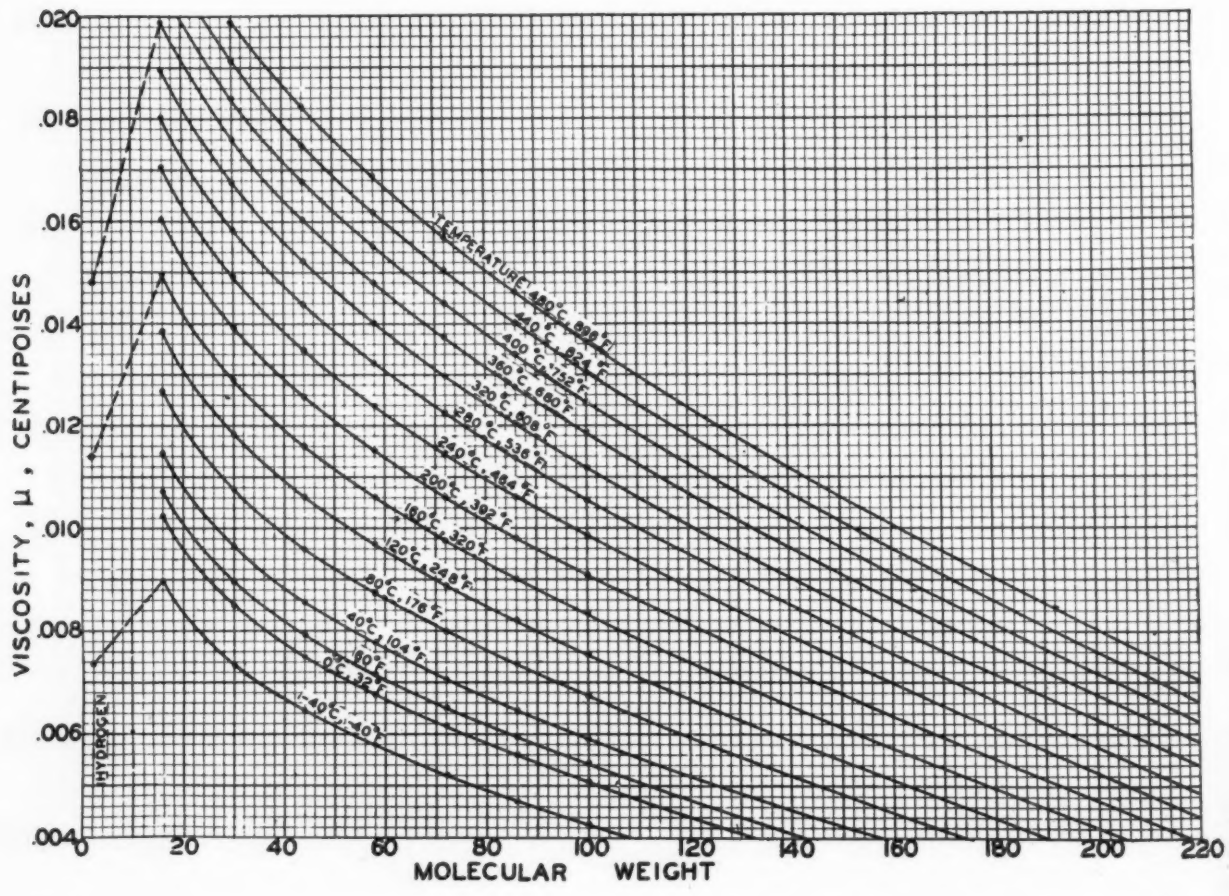
Fig. 4. Viscosity of paraffinic hydrocarbon gases at atmospheric pressure



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Centrifugal Compression of Hydrocarbon Gases*

By E. O. BENNETT
Consulting Engineer

Author's foreword: This discussion is not a mathematical or thermodynamical treatise on compressors or combustion turbines, but simply a brief historical discussion of them setting out where I think they may fit into your picture. Nothing in this discussion is intended to condemn or derate reciprocating equipment, which plays such an important part in our great industry.

THE use of high rotative speed centrifugal pumps for the moving of liquid-phase fluids in all branches of the petroleum industry is very general. In fact, one would have to look quite thoroughly to find other than a crankless rotating type machine for liquid pumping in any petroleum industry plant installation placed in operation during the last few years.

The question is often asked—Is there any reason why high speed centrifugal pumps cannot move vapor phase fluids as well as liquids? Development during the last few years permits the answer to this question to be "No."

A brief historical review of the development of prime movers shows that man's first knowledge and use of the expansive force of the vapor of water is unknown; however, records do show that such knowledge existed earlier than 150 B. C. In a treatise of about that time entitled "Pnuematica," Hero, of Alexandria, a Greek mathematician, described not only existing devices of his predecessors and contemporaries but also an invention of his own which utilized the expansive force of steam for raising water above its existing natural level. He clearly describes three methods in which steam might be used directly as a motive power: (1) Raising water by its elasticity, (2) elevating a weight by its expansive power, and (3) producing a rotary motion by its reaction on the atmosphere. The third method, which is known as "Hero's Engine," is described as a hollow sphere (Fig. 1) supported over a caldron or boiler by two trunnions, one of which was hollow and connected the interior of the sphere with the steam space of the caldron. Two pipes, open at the ends and bent at right angles, were inserted at opposite poles of the sphere, forming a connection between the caldron and the atmosphere. Heat being applied to the caldron, the steam generated passed through the hollow trunnion to the sphere and thence into the atmosphere through the two bent pipes. By the reaction of the steam against the atmosphere when escaping through the pipes, the sphere was caused to rotate and here is the primitive steam reaction turbine and first known rotating mechanical power device.

In his writing, Hero makes no suggestions concerning the application of the devices he described for any useful purpose. From Hero's time until the late sixteenth and early seventeenth centuries, there is no record of any further progress with such engines, though some evidence is found that such devices, as were described by Hero, were sometimes used for trivial purposes, such as the blowing of an organ or the turning of a skillet.*

The above historical discussion shows that the general idea of rotary type engines was known long in advance of any knowledge of reciprocating types, which first came into prominence during the time of Watts about 1760.

Reciprocating type engines for general power purposes were in use prior to the development of high speed turbines; and as a natural sequence, because of their slow speeds, the use of reciprocating type fluid compressors, based on the same fundamental features of mechanical design, followed and are still with us.

Later steam turbines of various types, with speeds up to several thousand revolutions per minute were developed and placed in practical operation and provided prime movers for electric current generation and for the turning of centrifugal pump shafts, fans, and other high speed units for liquid transmission in general industrial use, including low pressure gas pumps, known as blowers.

With the development of high speed turbines and motors, centrifugal pumps for the handling of liquid phase fluids became universal throughout the petroleum industry and there are now many thousands of such pumps delivering variable quantities against exceedingly high pressures with practically trouble-free results.

The same principles of design that are used in centrifugal pump construction are used in the design of centrifugal compressors. The only difference between the two being that the centrifugal pump handles relatively non-compressible fluids, whereas the centrifugal compressor, often called a turbo-compressor, handles compressible fluids. (See Fig. 2, cross section through centrifugal compressor).

"There is a tendency among engineers to confuse a centrifugal compressor, either with a rotary compressor or with a reversed steam turbine. It may not be amiss, therefore, to point out that it resembles neither. The rotary compressor is merely a positive compressor with rotary instead of reciprocating pistons and requires either contact parts or sealing liquid, or both. In general it is much more subject to wear than a reciprocating machine, and in most cases requires valves. In general, it is both inefficient and short lived and for this reason its appearance in industry has not been general.

"A mechanism such as the steam turbine cannot be operated effectively in reverse, as a pump, for a reason very similar to the well known fact that a Pelton wheel cannot be used as a centrifugal water pump. The steam turbine is designed primarily to utilize efficiently the kinetic energy of an expansible fluid, but is not adapted to reverse this process. While the mechanical efficiency of a steam turbine under the best conditions may be 75 to 80 per cent, an attempt to use it in a reverse process would result in an absurdly low efficiency, making its use uneconomic."†

Centrifugal pumps or compressors are designed upon entirely different principles than steam turbines but are capable of giving efficiencies, with proper design, of well over 80 per cent:

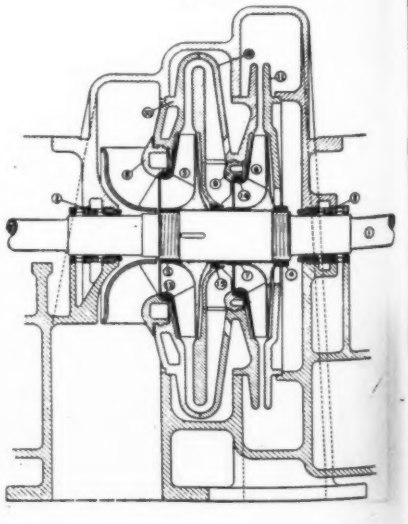
*Presented before Natural Gasoline Association of America, Dallas, Texas, April 12-14, 1944.

*Babcock & Wilcox publication, 1913.

†W. H. Carrier, American Society of Refining Engineers, December, 1925.

Fig. 1

Fig. 2



Guessing and gazing are out when it comes to buying your flow control equipment. Because, for even the simplest operation, the valve must be of correct design to obtain maximum efficiency. This not only includes basic type, such as Globe, Angle, Gate, "Y", Check, etc., but such factors as suitable stem action, bonnet construction, working pressure and especially the materials used in the body and mountings.

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Fig. 1944—Stainless Steel "Y" Valve for 125 pounds W. P. Has flanged ends, with outside screw rising stem threaded through bronze yoke bushing and bolted flanged yoke bonnet. Body can be provided with cleanout pockets on special order. This type of valves provides the straightway full flow area of the Gate valve plus the throttling feature and easy regrinding and renewability of disc of the Globe valve, thereby effecting considerable savings in maintenance.

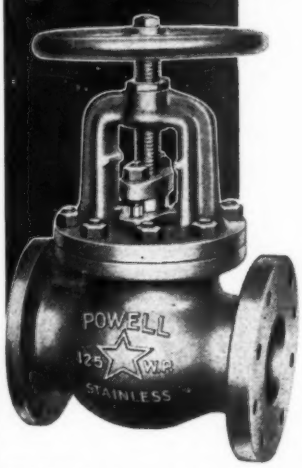

Fig. 2457—Large size Stainless Steel Globe Valve for 125 pounds W. P. Has flanged ends, outside screw rising stem threaded through bronze yoke bushing, full round bolted flanged yoke bonnet, and plug type disc. Sizes, 4" to 12", inclusive.

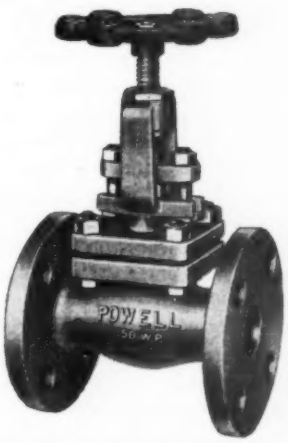

Fig. 1979—Stainless Steel Globe Valve for 150 pounds W. P. Has flanged ends, outside screw rising stem threaded through bronze yoke bushing, bolted flanged yoke bonnet, and plug type disc. Sizes, ¼" to 3", inclusive.

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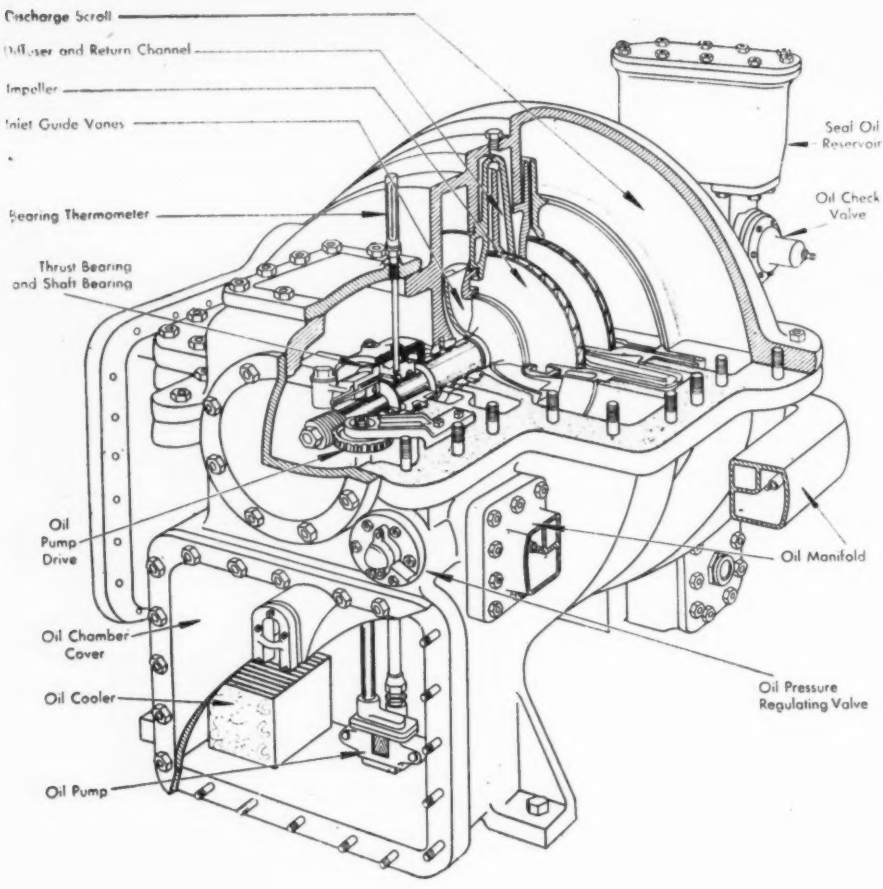


Fig. 3

and it is believed that continued development and use of such units will permit further increases in their efficiencies.

A centrifugal compressor has one feature in common with a turbine and that is freedom from wear and of maintaining constant efficiency throughout its life. The centrifugal compressor has the same simplicity of operation as a turbine. In addition to these features it is a machine, which, when actuated by a suitable prime mover, is capable of transferring energy to a fluid whether such fluid is in a vapor or liquid phase with very excellent operating efficiencies.

A centrifugal compressor requires no valves or rubbing surfaces, other than its two main shaft bearings; and its successful operation is not dependent upon extremely close rotating and reciprocating types of gaseous phase pumps or compressors.

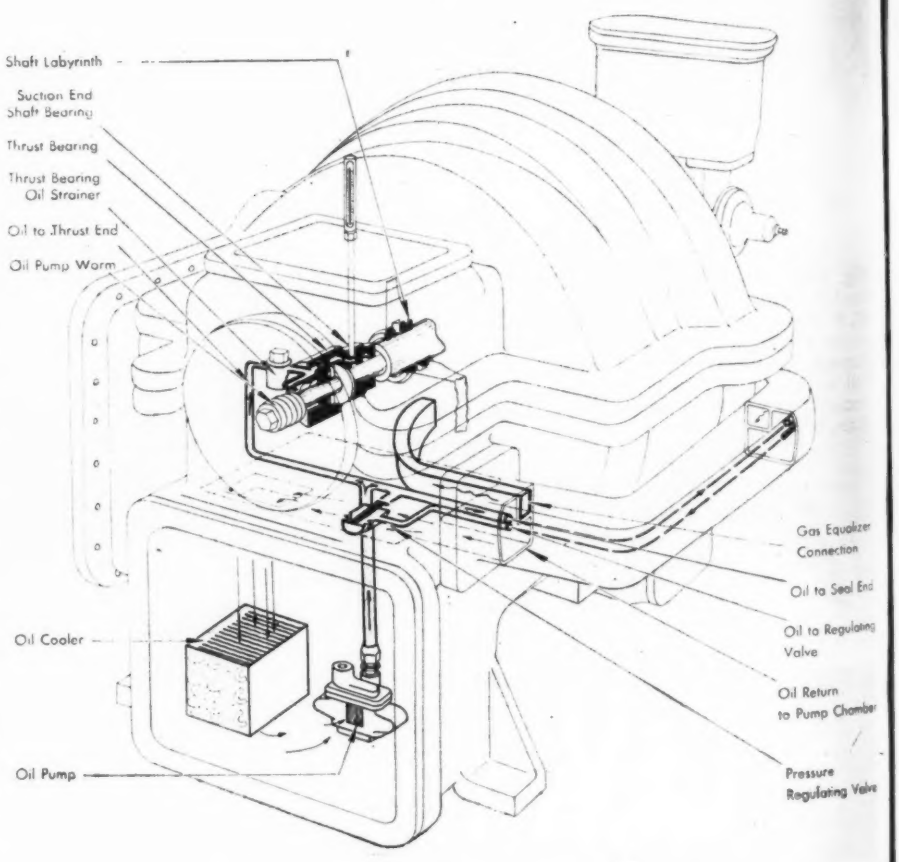
The same fundamentals of design enter into both centrifugal pumps and centrifugal compressors except that the centrifugal compressor, due to the necessity of handling compressible fluids of less density than normal centrifugal pumps handling liquids, is, in most cases, operating at considerably higher rotating speeds. Higher speeds in centrifugal compressors such as used in turbine practice call for large diameter shafts that make a very rugged type machine. Steel disks are used in the construction of the rotary members to provide adequate strength. Where several stages of compression are required, thin metal labyrinths are used to prevent leakage between stages. Such a labyrinth seal is very effective and is practically frictionless. Such seals have been used in steam turbines for many, many years, and there is nothing new or radical in their use. No metal contacts exist in the labyrinth seals.

The only parts of a centrifugal compressor subject to mechanical wear are the two main shaft bearings, and it is a well known fact that with proper design and lubrication the life of a high speed bearing is very great, and the shafts and bearings will retain their original dimensions for a great many years. (Figs. 3, 4, and 5.) Reciprocating machines of modern design have bearings that last much longer than those of the early machines but cannot begin to compare with the life of high speed centrifugal equipment.

Due to its simplicity of design and minimized number of wearing parts, the mechanical efficiency of a centrifugal turbine is found to be over 99 per cent. The mechanical efficiency of a reciprocating type unit is somewhat less.

The efficiency curve of a centrifugal

Fig. 4



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compressor is very flat between 50 per cent and 100 per cent volumetric capacity. The overall efficiency of this type unit is approximately 85 per cent at maximum designed load, and falls off slightly if the load, or output volume, is increased or decreased.

The head, or discharge pressure curve, falls off with a capacity beyond the maximum; so, too, does the compression ratio. The machine is primarily a constant head unit; however, the head may be varied by changing the rotating speed.

A machine with the above characteristics is very desirable for gasoline recovery plant operations as the greatest possible uniformity in flowing conditions may be obtained, and shock and vibration will be completely absent. The absence of vibration or pulsation in high pressure lines is extremely desirable in high pressure operations in connection with condensate or natural gasoline recovery as most pipe failures which occur are from pulsation and vibration. Freedom from vibration and unbalanced dynamic forces lessens the amount of concrete and foundations required for centrifugal compressors and eliminates the difficulties with vibration in field lines, where but few compressor cylinders are used in reciprocating machines.

One of the most disturbing factors in the metering of gas has been pulsations. Centrifugal type machines will entirely eliminate such troubles and minimize wear and tear on metering equipment.

Centrifugal compressors, complete with prime movers, generally steam turbines, are estimated to cost from $65 to $85 per hp. as compared to $105 to $135 per hp. for reciprocating equipment with comparable installation quality.

Centrifugal compressors are now built for discharge pressures up to 400 lb. per sq. in.; the limiting factor in this regard being the strength of the case. No reason is seen to prevent the design of units suitable for operating up to 3000 lb. per sq. in. or more. Cases may be designed for balanced inside and outside pressures and inserted in a sufficiently strong "gun-barrel" outer case. This principle has been successfully used in fluid meters where a 25 to 50-lb. meter may be used for pressures up to 3000 lb. per sq. in. or more.

The compression ratio of a centrifugal compressor is dependent upon the intake temperature of the fluid being handled, and presently completed designs will operate approximately as shown in the following table:

Fluid pumped	Four wheels	Six wheels
Average natural gas	2.4	4.1
Air	2.8	4.5
Propane	7.0	16.0
Butane	10.0	25.0

Higher ratios can be obtained by the use of interstage coolers for minimizing inlet temperature to successive stages.

Peak, or designed pressures, for a multi-stage centrifugal or turbo-compressor cannot be exceeded and destructive pressure due to accidental closure of a valve on the discharge system cannot be developed. For this reason relief equipment such as safety valves or frangible blowout disks are not required, thereby further minimizing installation costs.

A centrifugal compressor has a definite pressure-volume curve for its designed speed, and the pressure-volume relationships will have a separate curve for each rotative speed.

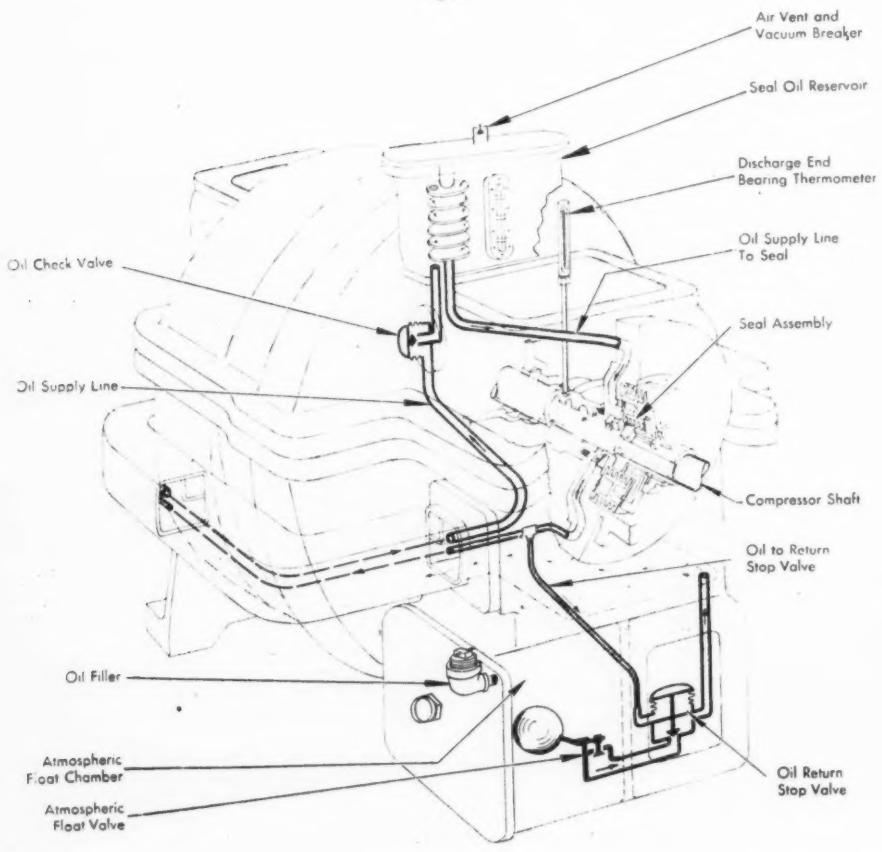
In operation, the gas to be compressed enters the rotating element at apertures around the shaft of the machine. The rotating element imparts velocity to the gas by the centrifugal motion. This velocity increases with the increasing radial speed of the impeller section it passes through until it reaches the discharge tip of the impeller, where the energy due to velocity is converted to pressure energy in passing through the stationary vanes around the impeller. As the velocity is decreased the pressure is increased and the moving volume of gas is carried to the next wheel of the unit at the increased pressure where a second increment of pressure is added by the same process. The final discharge pressure required determines the number of stages required.

Variation in speed for driving centrifugal compressors depends upon the type of prime mover used. Where steam turbines are used for this purpose a wide range is available by throttle control of the turbine. Where constant speed electric motors are used variable compressor speeds may be obtained through the use of an efficient fluid transmission, now found in many places in industry. If a combustion turbine is used, a combinaton of turbine speed control and fluid transmission may be used. Speeds of centrifugal compressors now in use run up to 6000 to 10,000 r.p.m. but need not be so limited. Centrifugal compressors are designed to have a peripheral speed of approximately 750 ft. per sec.

Much interest has been developed in the possible use of combustion turbines in place of team turbines in the natural gas and gasoline industry. (Fig. 6) The development of this type of prime mover has been very rapid, and its general appearance in both stationary and mobile units is predicted after the war is over.

At the present time the combustion turbine is used to convert hot waste gases of combustion to useful power. It is in operation in some of the modern refinery processes and is converting otherwise lost energy into useful work.

Fig. 5



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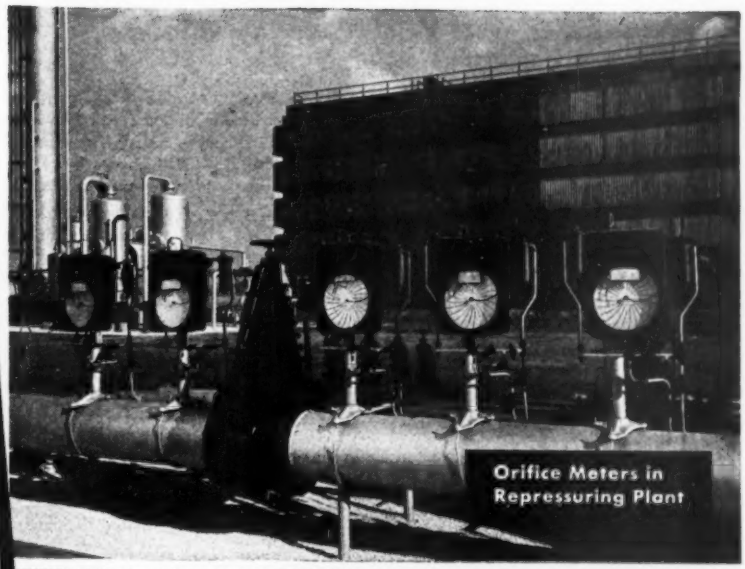
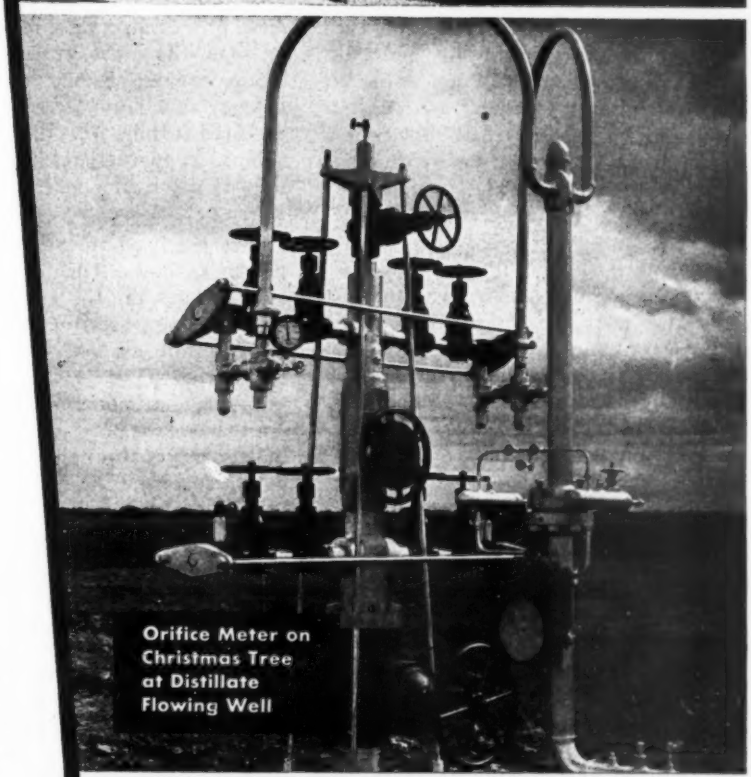
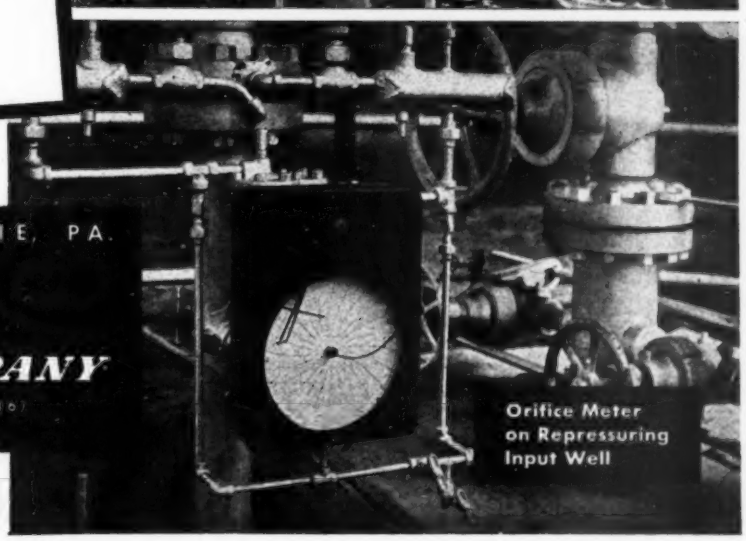


Orifice Meters in Repressuring Plant



Orifice Meter on Christmas Tree at Distillate Flowing Well



Orifice Meter on Repressuring Input Well

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Hydrocarbons in the Gasoline Fraction of Seven Representative Crudes

American Petroleum Institute Research Project 6 made its second report of an investigation on the analysis of the gasoline fraction of representative crude petroleums at the National Bureau of Standards, before the annual meeting in Chicago, November, 1943. Alphonse F. Forziati, Charles B. Willingham, Beveridge J. Mair, and Frederick D. Rossini made the investigations and presented the paper.

The first report, made the year previous, showed preliminary results on East Texas and Oklahoma crudes. The second report gives the results obtained on the hydrocarbons in the gasoline fraction of 7 different naphthas covering the paraffins and naphthenes to 102°C. and the aromatics to 160°C. Subsequent reports will deal with the paraffin and naphthene hydrocarbons above 102°C. and the aromatics above 160°C.

Samples for analysis were selected so as to cover the largest possible range in composition; included one high in aromatics, one high in isoparaffins, one high in normal paraffins, and one high in naphthenes. They came from the following fields: Ponca, Oklahoma; East Texas; Bradford, Pennsylvania; Greendale-Kawkawlin, Michigan; Winkler, Texas; Midway, California, and Conroe, Texas. The fractionating processes of adsorption and distillation were used in the analysis.

Present trends of design have been for large units, but development of the turbo-super charger for airplane engines indicates that it will be possible to develop and operate small power units.

General mechanical horsepower in the United States started with the reciprocating steam engines, which was followed by the steam turbine, the ordinary gas or gasoline engine, and the diesel engine. This source of power is now being augmented by the gas turbine. It is estimated that the sum total horsepower hours annually produced by all of the above mechanical power units in the United States exceeds 450 billion, which is about 3000 hp.-hr. of work for each person in the United States annually.

The reciprocating steam engine was a complex, inefficient machine requiring a boiler plant. It was largely replaced by a more efficient steam turbine, but the necessity for the boiler plant remained. Next came the gasoline and diesel engines with increased efficiencies and the elimination of the boiler plant, but with the addition of mechanical complexities. Each of the above type units has a definite place in industry and does not need discussion at this time. The efficiencies of the gasoline and diesel prime movers is considerably higher than the older type reciprocating steam engines. Steam locomotive efficiency runs from 8 to 12 per cent. A gas-fired turbine-driven locomotive developed in Switzerland prior to the war showed an overall efficiency of 15 to 18 per cent.

The gas-fired turbine consists of a power turbine element and an axial type blower on the same shaft. The blower compresses a large volume of low pressure air which is supplied to the burner (Fig. 4). Fuel in proper proportion is mixed with the air and ignited, and the hot gas mixture of combustion passes through and actuates the power turbine. The excess power over and above that required for compression of air for combustion is the power available for useful work. The efficiency of the gas-fired turbine is governed by the temperature of the gaseous mixture reaching its rotating elements. A turbine having an efficiency of 18 per cent with combustion gases at 1000°F. will attain an efficiency of 23 per cent when the inlet temperature is raised to 1200° F. With new metals now being developed it is anticipated that operating temperatures may go as high as 1500°F. with corresponding increases in efficiencies.

Recent attention to progress of the gas turbine may make it appear that this method of developing power from direct fired gases is a new invention. Patents were issued on this type power unit during the latter part of the 18th century, and at that date it is obvious that engineers of that time recognized the advantages of a single element rotating power unit free of the complexities of a steam plant.

The high stage of development of the steam turbine no doubt had much to do with the parallel development of the gas-fired turbine. Metallurgy of materials probably had more to do with its recent fast growth than any other single factor.

The approximate temperature of the exhaust from a turbine with 1000°F. inlet temperature is a little over 600°F.; by utilizing the exhaust heat to preheat air from the axial compressor to the burner unit the efficiency of the unit may be raised by approximately 50 per cent.

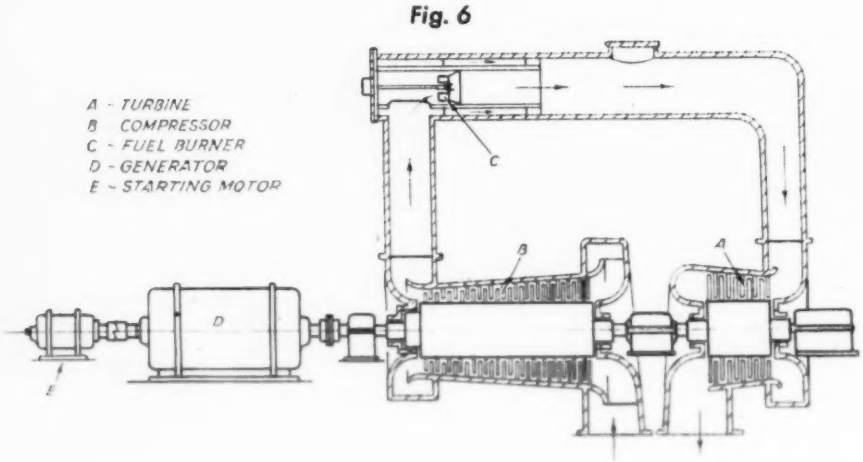
Higher operating temperatures require increasing compression ratios in the compressor unit but also increase the overall thermal efficiency of the unit. The efficiency of the compressor part of the gas turbine unit has much to do with the overall efficiency of the unit. By increasing the efficiency of the compressor unit from 0.75 to 0.90, a change of 20 per cent, an overall efficiency of 400 per cent in maximum thermal efficiency is obtainable.

It is not believed that the gas-fired unit will replace the steam actuated type, but it is felt a unit operating free from water supply will have many inherent advantages in gas and gasoline plant operations in certain areas where water is scarce and that which is available is of poor quality. Direct fired turbines can be fired with any liquid or gaseous fuels and should be well adapted to certain power requirements in gasoline plant operations.

A centrifugal compressor unit driven by a gas-fired turbine will give the simplest mechanical designed unit yet developed and offers the natural gasoline industry the possibility of new features in design at a greatly reduced horsepower cost. Exhaust heat from the turbine, with proper design, could supply much of that required for processing.

A gas fired turbine will not start at the turn of a valve as will a steam turbine, but must have some auxiliary device to rotate its moving element up to approximately 20 per cent of normal speed to produce a sufficient volume of air to support combustion.

Fig. 6



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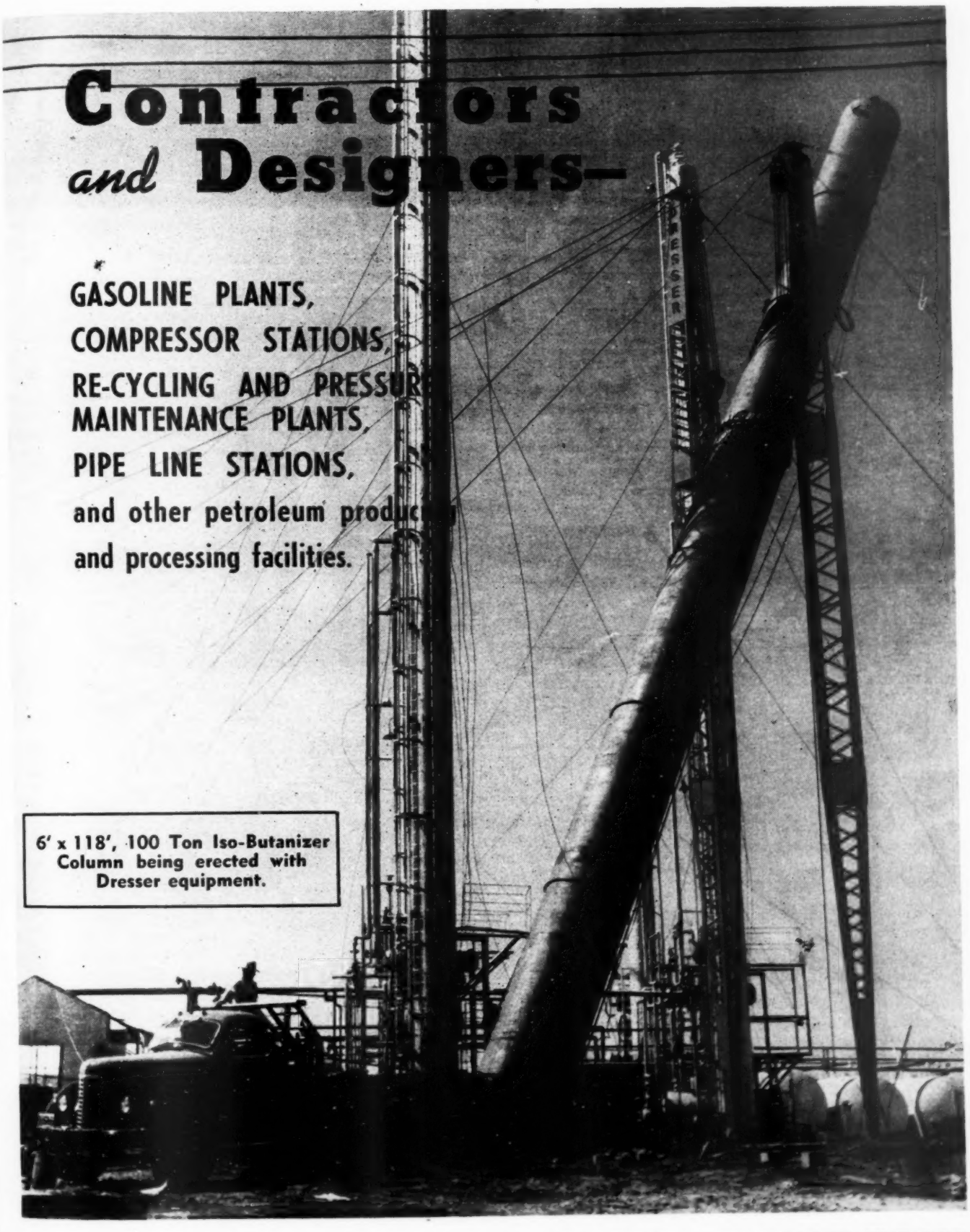

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Maximum Hydrocarbon Utilization With Natural Gas as a Chemical Raw Material*

By JAMES E. PEW and FRANK H. DOTTERWEICH
Natural Gas and Natural Gasoline Division of PAW

THE growth of the gas industry during peacetime was accompanied by developments and operating problems primarily related to the use of natural and manufactured gas as a source of fuel and energy. While these activities were being given major attention, a new technology was being evolved—that of petro-chem development, in which gaseous hydrocarbons were being distorted, rearranged, and recombined to yield chemical raw materials from which useful products could be manufactured. Today the swift tempo of war activities places increased emphasis upon these petro-chem operations, capable of supplying our tremendous war machine with vital war products, many of which find natural gas as the basic raw material.

The wartime developments are not of a static nature but will progress steadily until the not-too-distant day where a substantial portion of our hydrocarbon derivative chemical products will have their origin in natural gas. In this paper the authors will endeavor to note processes presently available, together with those which will become generally available in the postwar period by means of which we may hope to utilize more efficiently the full range of our hydrocarbon raw material and, in addition, to analyze the effect of these petro-chem operations upon present and postwar activities of the gas industry. The future of natural gas in its capacity as a chemical raw material has occupied much space in technical publications and general discussions, and this subject continues to grow in stature. This is true, at least in part, because of the rapidly advancing technologies, which appear destined to have profound effect upon the future of the industries involved. Natural gas is known as the ideal fuel with its superb performance bringing about the development of special heating and cooling equipment and thus furthering the earlier standardized applications, such as cooking and heating.

The stability of the gas industry and, more particularly the natural gas section, has been built around a numerically substantial domestic load, which condition has permitted it to weather the storms of depression. In looking into the future the question arises as to what effect petro-chem developments are to have upon this industry. Naturally this problem resolves itself into, first, an analysis of available natural gas reserves; second, a consideration of the success of new commercial processes proposed with natural gas as their chemical raw material, and, third, a quantitative study of the extent to which the use of natural gas therein will deplete those reserves.

Natural gas reserves. Natural gas reserves are today estimated at 110 trillion cu. ft. With marketed natural gas production approximately 3¼ trillion cu. ft. in 1943, a supply sufficient for the next 30 or more years appears to be definitely assured. This compares very favorably with an estimated oil production known reserve ratio of 14 years.

A further evaluation of relative importance of natural gas in the natural resources picture is provided by a comparison of natural gas and oil reserves, on a thermal or weight basis, either of which reveals their near equivalence. Probing more deeply behind these reserves figures, it may be determined that estimates of natural gas reserves have risen phenomenally in less than ten years. A 1935 estimate of 62 trillion cu. ft. of gas reserves appeared optimistic beside others at that time; yet, in the ensuing nine years, during which more than 25 trillion cu. ft. of gas have been withdrawn from the nation's underground reservoirs, reserves estimates have risen to the present 110 trillion cu. ft. for the nation.

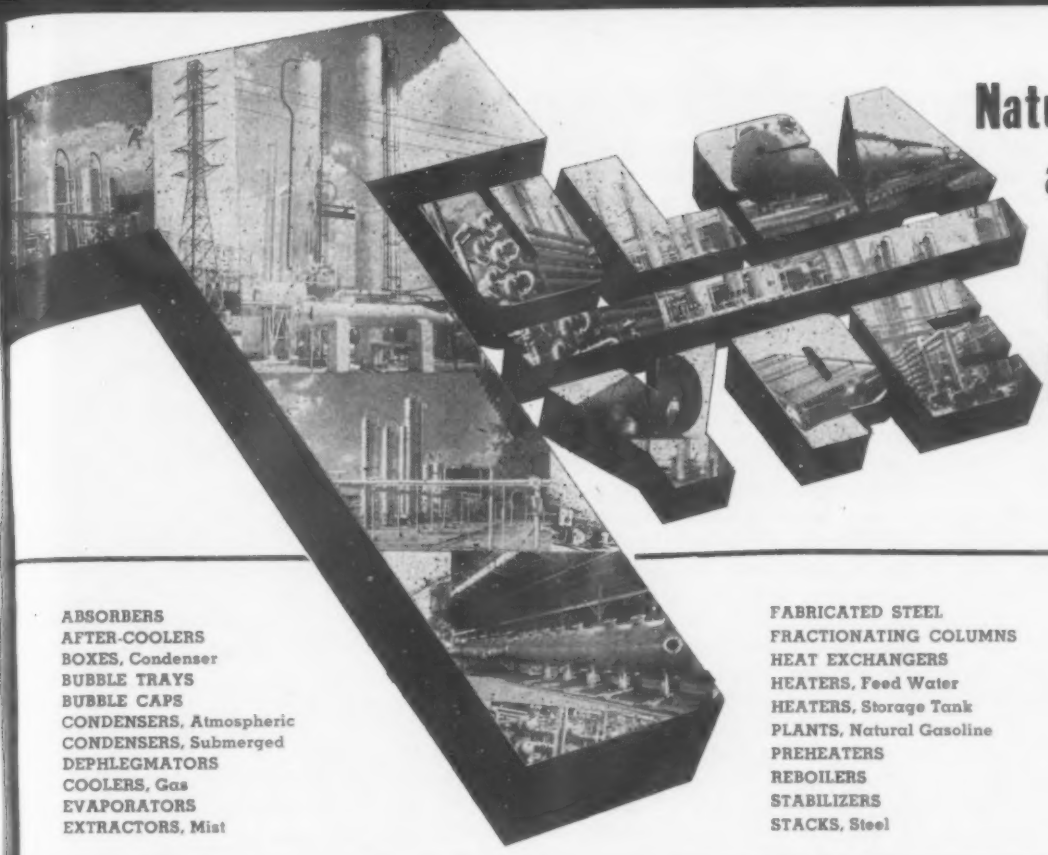
Meanwhile, an analysis of discoveries in the highly active area embracing South Arkansas, Louisiana and the Coastal Plain of Texas reveals further that, in the years between 1934 and 1943, the proportion of gas and gas-condensate to total discoveries rose from 24 to 52 per cent, with gas-condensate discoveries largely uncovered in deeper drilling increasing from 11 to 36 per cent of the total during this period. The continuance and expansion of this deeper drilling program, undertaken as improvements in technique permits, may be expected to uncover an increasing proportion of fields of the gas-condensate type, existing under extremes of pressure and temperature, and these fields, productive of the lighter hydrocarbon fractions which are proving so valuable in wartime production programs, through the installation of cycling equipment may constitute the nucleus in the postwar period of the new petro-chem technology. So much is already evident: The period and magnitude of gas-condensate discoveries is adequate to justify appreciable capital outlay, as increasing amounts of the lighter hydrocarbon materials will be made available for chemical processing and, potentially, manufactured gas enrichment. The latter, gas enrichment with ethane-propane mixtures, should be given immediate attention by manufactured gas companies, if the advantages of a higher B.t.u. gas non-gumming and non-corrosive properties are to be attained.

But the gas industry has still greater possibilities ahead. The uses of natural gas to be hereinafter described are new uses, providing new markets. The gas companies possessed of a high degree of engineering skill and knowledge, with a fundamental awareness of the capabilities of their stock-in-trade, could look upon the new technology as an added source of revenue.

It is necessary to emphasize that a new market has been created for, as shall be seen, the needs of the United States for certain products in 1943 could have been not through conservation of natural gas reported lost and wasted by the U. S. Bureau of Mines in the 1942 Minerals Yearbook, carrying most recently published analysis of gas disposition (1941). Actual production exceeded 4 trillion cu. ft., with almost one-third of this being divided between repressured and stored gas (660 billion cu. ft.) and gas known lost or wasted (630 billion cu. ft.), The latter figure will be used in the calculation to follow as being both qualitatively and quantitatively indicative of the magnitude of this waste. Gas loss and waste in proportion to production is decreasing as indicated in Fig. I, but the figure is still far too great, despite the intensified efforts of the governing legislative bodies to reduce it to the absolute minimum.

New and proposed commercial processes. The importance and value of natural gas at present and, in the postwar period to an ever greater extent, is a measure of the volume available and the low critical material requirement for processing and production. By modern methods of extraction

*Presented before Southern Gas Association, New Orleans, Louisiana, March 23, 1944.



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and fractional distillation, natural gas may be separated into relatively pure saturated hydrocarbons. Valuable in their pure state as blending agents or, when especially processed, still more valuable as a chemical raw material, giving remarkable high yields of war products. Among these are high octane aviation gasoline, synthetic rubber, explosives, and plastics, all being made in great quantities with petroleum and natural gas as key components. Too, new processes and products are constantly undergoing development, and natural gas will continue to grow in importance as a chemical raw material.

In discussing the newer methods of conversion, not only into the essential raw materials, but also into the final products, it appears desirable to divide these into: (1) Processes directly concerned with the production of superior liquid fuels from natural gas, and (2) processes concerned with the production of other chemical raw materials.

Liquid hydrocarbon fractions from natural gas. Such hydrocarbons as propane and butanes occur in appreciable quantities in wet or casinghead gas, and are largely removed before the gas is marketed. At the present time the propane-butane fractions serve as liquefied petroleum gases and also as the feed materials from which certain aviation fuel components are derived. Production of the super aviation fuels, composed of select hydrocarbon fractions in definite proportions, requires large quantities of isooctane alkylates, cumene, tetraethyl lead, and other essentials. An appreciable amount of these ingredients has its origin in natural gas; in fact, a finished aviation fuel may be produced altogether from fractions obtainable in exploitation of the nation's gas-condensate fields.

The production of liquid hydrocarbon fractions from dry natural gas is presently receiving attention. The processes involved have been developed commercially by European powers and are related to those through which the Axis nations are now synthesizing gasoline from coal. The increasing reserves of natural gas in this country, viewed in conjunction with heightened consumption and decreased finding power of crude oil, are presently accelerating interest on this object.

In the past, liquid hydrocarbon fractions have been prepared by a process commonly referred to as the Fischer-Tropsch process. In this process, water gas (carbon monoxide plus hydrogen) is the raw material. In Europe water gas has been prepared with coal or coke as the starting raw material. However, with the modern steam conversion process, in which natural gas and steam are made to react to form water gas or hydrogen as an end product, a more reasonably synthesized liquid fraction is available. The importance of the process in relation to America's 110 trillion cu. ft. of gas reserves cannot be over emphasized for it makes natural gas well-nigh competitive with crude oil. Natural gas could possibly be one of the starting raw materials if the crude oil supply is to be supplemented or supplanted in the synthetic hydrocarbon fractions.

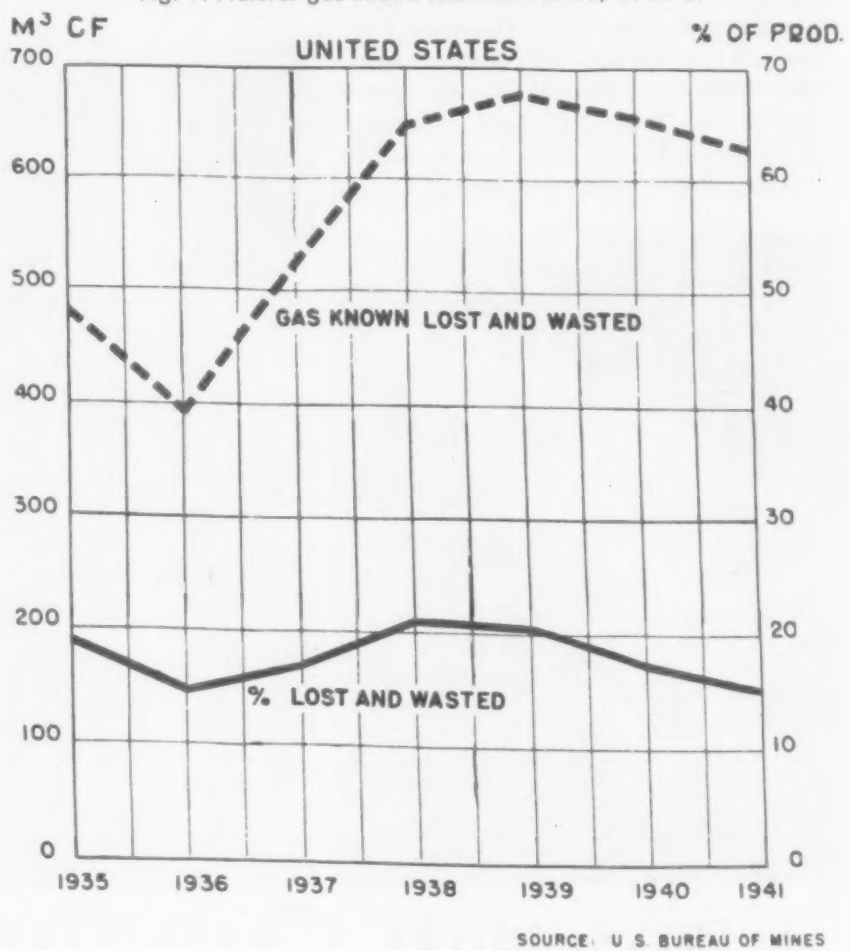
With natural gas as the starting raw material, three steps are involved: Reforming to water gas, synthesis into liquid hydrocarbon fractions, and recovery and separation. The three are already being practiced separately on a commercial scale, and the problem resolves itself into "flanging up" these operations and perfecting operating conditions so that this synthetic liquid may be produced on a favorable economic basis. Investigation of the combined processes is now being undertaken in pilot plant operations, with estimates as high as 4.2 gal. of liquid products recoverable per 1000 cu. ft. of dry natural gas, including fuel gas. This yield if proved practical is approximately equivalent to 1 bbl. of a mixture, (chiefly gasoline, diesel oil, and heavy oil) per 10,000 cu. ft. of dry natural gas.

Chemical processes — new and proposed. Chemical developments related to natural gas are numerous, and progress is being made constantly. In this paper major attention is to be directed to the preparation of products derived from natural gas that serve as chemical materials from which many useful products may be derived.

The steam conversion process, to some extent developed in this country, is outstanding because it reforms dry natural gas to water gas or hydrogen. Water gas, in addition to being the base product in the manufacture of liquid fuels, may be the starting point in the production of synthetic alcohol and formaldehyde. War and peacetime uses of hydrogen are many, but chief among them is the production of synthetic ammonia for use in explosives, fertilizers, and hydrogenation processes (principally in the production of super fuels).

The regenerative furnace process makes available still another method of cracking natural gas. This furnace, now ready for commercial operations, produces important starting chemical materials, such as acetylene, ethylene, and propylene from natural gas constituents, not excluding methane, but with ethane and heavier fractions more desirable. Still another method is provided in the

Fig. 1. Natural gas known lost and wasted, 1935-41



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Well-kept equipment delivers the best operating results for the least overall maintenance cost.

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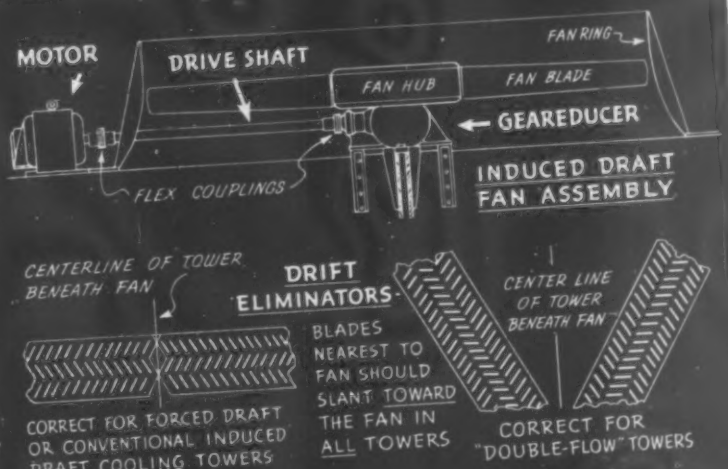
SPEED REDUCTION GEARS—Follow the manufacturer's lubrication instructions religiously. (Marley "Geareducers," although outstandingly rugged and trouble-free, nevertheless deserve and require the minimum care set forth on the name plate.) There is always slight "play" in ring and pinion gears, but if excessive, wear is indicated. Pinion shaft end play or fan shaft side play indicates excessive bearing wear. If oil leaks around either shaft, oil seals should be replaced.

DRIVE SHAFTS—Keep drive shafts in alignment and balance, all coupling bolts tight. Replace or repair universal joints or flexible couplings when worn. Lubricate these joints as necessary. (Marley's disc-type couplings require no lubrication.) Keep shaft guards securely in place.



MOTORS—Grease ball-bearing motors with an approved water-resistant lubricant every one to three months, according to manufacturer's instructions. Do not over grease.

Once a year check insulation value with a megger, or by similar means, and paint the motor winding with approved insulation varnish and the frame with anti-rust paint.

WOOD PARTS AND FRAMEWORK—Check drift eliminators each season to see that all blades are in place and alignment. If necessary to remove any section, make sure it is replaced with blade edges slanting toward the fan as illustrated in the accompanying sketch.

Well-designed filling (the "decking" or latticework inside most larger towers) will not sag or warp appreciably but if such condition is noted, correct it. Replace broken laths.

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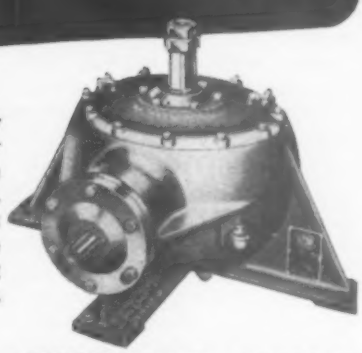

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electrical production of acetylene. This method is being thoroughly investigated in pilot plant operations, and may be expected to be of importance in the postwar production of acetylene.

The production of carbon black, of fundamental importance to the rubber, printing, and paint industries, has long utilized about one-tenth of this country's annual production of natural gas through the simplest of the chemical reactions into which methane, the principal component of natural gas, enters —combustion and thermal decomposition. Carbon black is today being prepared from natural gas alone in channel and roller plants (typical of contact methods of manufacture), and thermal and furnace plants. A product similar to the furnace type is also being prepared from degraded oil and natural gas in combination. It is interesting to note that the thermal production of carbon black had its origin in the derivation of hydrogen, from natural gas, with the thermal black representing merely a by-product. It is, then, possible to obtain two products through one process. The production of hydrogen is alone economically feasible, even in areas of high gas cost; the relatively cheap, coarse grade of carbon black obtained, capable of being used in extremely high loadings, represents additional revenue.

Oxidation process is now in commercial operation, with natural gas serving as a raw material in the production of formaldehyde, methyl alcohol, acetone, and acetaldehyde, among others. Present processes yield a mixture of these oxidation products, and economics require that the market absorb all of these derivatives if the high cost of production is not to be imposed upon any one end product. It is possible that more recently developed processes now undergoing examination will permit conversion of natural gas exclusively into one product, thus eliminating economic uncertainty. (The subject of producing oxy-hydrocarbon derivatives by alternative method is considered elsewhere herein.)

The cholorination of natural gas and its derivatives to form chlohydrocarbon solvents is of proved commercial importance, while their use has been greatly increased in war time. The peacetime uses of these compounds have been greatly curtailed or eliminated in order that they may be made available for war uses. These compounds are of great importance, both in chemical warfare and in the synthetic rubber industry, as well as in many other uses demanding near or absolute non-flammability plus excellent solvent power for oils, fats, and other organic materials. Improved processes of this type are continually being developed, and natural gas will remain one of the important raw materials.

The vapor phase nitration of natural gas hydrocarbons on a commercial plant scale basis has produced the four nitroparaffins: Nitro-methane, ethane, propane, and butane, thus making available for chemical synthesis a group of compounds with a potential range of usefulness unequaled by any other new group of organic chemicals. These compounds are more than just another group of new compounds because they open entirely new fields of organic chemistry, a field which some day may rival the development of the coal tar derivatives in magnitude and scope. At the present time their entire production is going into essential war uses for the synthesis of pharmaceuticals, dyestuffs, insecticides, rubber chemicals, photographic developers, textile chemicals, and resins together with their use in solvent applications. The entire postwar industry, particularly the highly specialized industries, should find these nitroparaffins a fertile source of improved and new chemicals for new and better products.

In addition to being of great importance as a raw material in the processes previously cited, natural gas is forging ahead along other lines. An example is the production of carbon disulphide, presently derived by heating sulphur and charcoal. Recently published laboratory research indicates that high yields of carbon disulphide may be obtained through the high temperature reaction of methane and sulphur, and that methane and other hydrocarbons offer possibilities as cheap raw materials in this production, such new processes, making use of natural gas as a chemical raw material, are introduced daily.

Quantitative requirements of natural gas in its capacity as a chemical raw material. Diversified opinions have been voiced regarding the magnitude of demands that may be made of natural gas in its capacity as a raw material for the rapidly developing petro-chem industry. The view most generally held, and one in which the authors have concurred, is that demands will be slight by comparison with the enormous volumes annually used for fuel. An attempt has accordingly been made in the following paragraphs to evaluate these demands quantitatively, based upon production figures for various organic chemicals which were synthesized during 1943. As will be shown, all of these could have been produced with a fraction of the natural gas loss and wastage to which reference was earlier made.

Methane is suitable for the production of acetylene, particularly by electrical methods, and may also be used in the steam conversion process whereby formaldehyde or methanol may be obtained. With those possible exceptions, ethane, propane, and butane provide more desirable raw materials. Accordingly, use has been made of these fractions in the following study, with the lean gas then being converted into methanol and formaldehyde sufficient to fulfill the requirements of these products, and the remainder entering into the synthesis of liquid hydrocarbon fractions by means of the Fischer-Tropsch process. The conversion factors used are not improbable for the early postwar period.

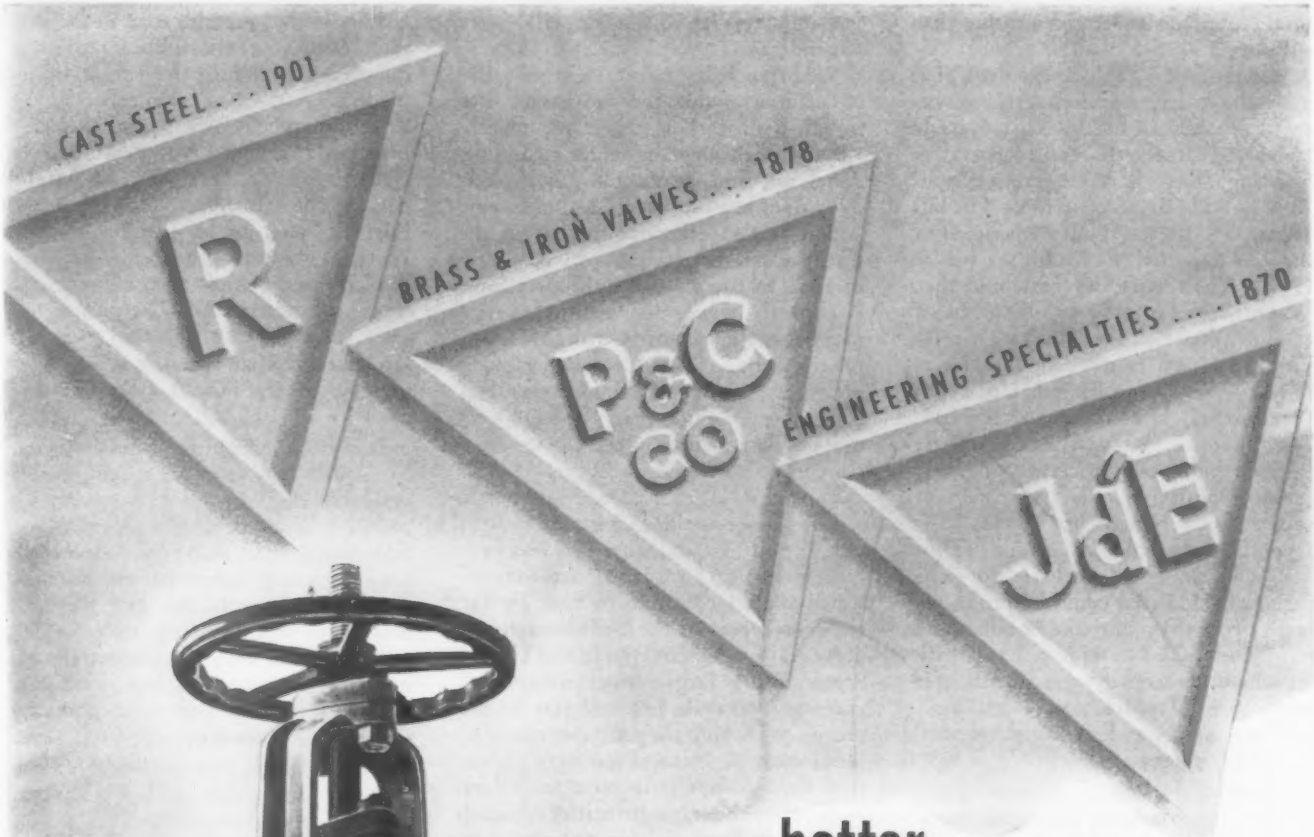
In the recovery of the heavier hydrocarbon fractions from natural gas, their conversion into basic chemical raw materials, and their subsequent synthesis into organic liquids, the latest available recovery and yields were used. Inasmuch as part of the data is restricted,

TABLE I

Synthetic organic chemical	U. S. 1943 production, lb.[1]	Possible processes and raw materials		
		Basic hydrocarbon raw material	Intermediate hydrocarbon raw material	Processes
Acetaldehyde	224,445,142[2]	Ethane propane	Acetylene	Regenerative cracking.
Acetic acid (100 per cent)	264,898,632[2]	Ethane propane	Acetaldehyde	Regenerative cracking.
Acetone[3]	336,000,000	Butane	Isopropyl alcohol	Tubular or regenerative cracking.
Acrylic resins	25,000,000[4]	Butane	Ethylene propylene	Tubular or regenerative cracking.
Ethyl alcohol	344,000,000[4]	Ethane propane	Ethylene	Tubular or regenerative cracking.
Formaldehyde (40 per cent)	485,000,000	Methane		Steam conversion or catalytic oxidation.
Methyl alcohol	430,000,000[4]	Methane	Water gas	Steam conversion.
Isopropyl alcohol	380,000,000	Butane	Propylene	Tubular or regenerative cracking.
Vinyl resins[5]	100,000,000	Ethane propane	Acetylene ethylene	Regenerative cracking.

[1]Approximated by *Chemical and Metallurgical Engineering*, February, 1944.
[2]From U. S. Tariff Commission (1942 production).
[3]It is assumed that the greater portion of acetone is derived from isopropyl alcohol as shown.
[4]Estimated from basic data in *Chemical and Metallurgical Engineering*, February, 1944.
[5]Includes vinyldiene chloride.

Material requirement: The total production of synthetic organic chemicals, by processes as shown, could be produced from the recoverable ethane, propane, butane fractions of 480 billion cu. ft. of natural gas (about 75 per cent of the 1941 gas lost or wasted) with the accompanying methane and heavier residue converted into approximately 44.4 million bbl. of gasoline, diesel, heavy oil mixture via the steam conversion and Fischer Tropsch processes.



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total requirements are given rather than any detail.

Reference to Table I divulges that the estimated production of these synthetic organic chemicals, as listed, could be derived largely through regenerative cracking from the recoverable ethane, propane and butane content of 480 billion cu. ft. of gas (about 75 per cent of the gas reported lost and wasted in 1941). The residue dry gas could then be synthesized into 44.4 million bbl. of gasoline, diesel oil, and heavy oil mixture. An alternate method, illustrative of the diversity and flexibility of available processes, is considered in Table 2. This method is constructed chiefly around oxidation processes presently being employed in the conversion of natural gas derivatives to certain basic chemical raw materials of use in the war effort. The synthetic organic chemicals indicated could be produced, again, from the reported 630 billion cu. ft. of gas loss and wastage in 1941, with the remaining semi-dry gas available for synthesis into approximately 55.5 million bbl. of a gasoline, diesel oil, and heavy oil mixture.

Notably, also, the production of the majority of synthetic chemicals itemized in Tables 1 and 2 was achieved principally through use of ethane, propane, and butane, or less than 20 per cent by weight of the natural gas. Further, in view of the fact that ethane, propane, and butane fractions are presently extracted from natural gas and are readily transportable by modern methods, this study loses its hypothetical character and assumes practical economic stature. It is, then, interesting to note that although dry natural gas (principally methane) is of importance as a chemical raw material, analysis of the extent situation suggests that the heavier available fractions be utilized. Such use will preserve for the natural gas industry its source material—dry natural gas.

Additional dry natural gas will also be made available for conversion into liquid hydrocarbon fractions, chiefly the aforementioned mixture of gasoline, diesel oil, and heavy oil. Pilot plant operations are now getting under way, and it is altogether likely that in the near future natural gas will be a raw material in commercial scale operations. A potentially enormous volume of natural gas could thereby be utilized in supplanting the anticipated early decline in productivity of crude oil. However, it is the authors' opinion that, although natural gas may be used in this capacity, its conversion to liquid hydrocarbons will take place in locations readily accessible to one or more fields but inaccessible to pipe line outlets, and where gas was, perhaps, even being wasted. Petroleum reserves should continue to bear by far the greater part of the load through imports and new discoveries in the United States. When large-scale conversion is necessary, oil shale and coal may be expected to provide the principal raw material sources. Natural gas may play a part therein, but only on a secondary scale, since the huge quantities required for Fischer-Tropsch conversion may be prohibitive. Moreover, potentially greater yet less exhaustive needs exist for natural gas in its capacity as a chemical raw material.

The future of natural gas as a chemical raw material. An analysis of the future of natural gas in this capacity as a chemical raw material has its background in the role assumed in World War II. Today large quantities enter into the production of carbon black, absolutely essential in the successful use of synthetic rubber, not only for tire-compounding, as was the case with natural rubber, but for all other uses. Appreciable quantities of natural gas derivatives are also used in the production of synthetic rubber. Still other quantities enter into the production of modern aviation fuel. Some 50 per cent of the emergency synthetic ammonia is produced from hydrogen derived through the decomposition of natural gas by the steam conversion process. Further, an as yet small portion of the synthetic organic chemicals listed in Tables 1 and 2 finds natural gas as the starting raw material. The present use of natural gas as a chemical raw material is in itself an amazing accomplishment, strongly indicative of postwar use.

It is evident from the foregoing considerations that the chemical product derivatives of natural gas provide the public with a potential source of new and improved materials — materials with amazing industrial applications, developed through the gas chemist's molecular magic. What may be less obvious is that they also present the gas industry—particularly, but not necessarily exclusively—with a potential source of new revenue.

By and large, the gas industry has played a passive role in the attainment of experience relating to the new petrochem developments, as well as in the technical research which that experience precludes. It is to be hoped that the establishment of the Institute of Gas Technology at Chicago, Illinois, typifies a dress rehearsal for a more active role—one in which Frank C. Smith, the president of the Southern Gas Association, has been most aggressive in demanding. The important work of the Gas Institute must be continued, even expanded, under the gas industry's sponsorship. But this is only a start. Outposts should be established in colleges and universities throughout the country through grants set up by the gas industry.

From the foregoing it is evident that the natural gas industry has unlimited possibilities in the postwar period and many years thereafter. The reserves guarantee many years of successful operations with the heavier derivatives of natural gas becoming of increasing importance as chemical raw material in the ever expanding petro-chem operations. Although dry natural gas is of importance as a chemical raw material, less exhaustive needs exist for it, with present trends suggesting that the heavier fractions are more desirable for chemical processing. These conditions should preserve for the natural gas industry its source material—dry natural gas. Thus, a balanced market is being created to use the complete range of our gaseous hydrocarbons, assuring maximum hydrocarbon utilization with natural gas as a raw material.

☆ ☆ ☆

TABLE 2
(Alternate method)

Synthetic organic chemical	U. S. 1943 production, lb.[1]	Possible processes and raw materials		
		Basic hydrocarbon raw material	Intermediate hydrocarbon raw material	Processes
Acetaldehyde	224,445,142	Ethane propane	.....	Oxidation.
Acetic acid (100 per cent)	264,898,632	Ethane propane	Acetaldehyde	Oxidation.
Acetone	168,000,000	Ethane propane	.....	Oxidation.
	168,000,000	Butane	Propylene	Tubular or regenerative cracking.
Acrylic resins	25,000,000	Butane	Ethylene propylene	Tubular or regenerative cracking.
Ethyl alcohol	344,000,000	Butane	Ethylene	Tubular or regenerative cracking.
Formaldehyde (40 per cent)	485,000,000	Ethane propane	.....	Oxidation.
Methyl alcohol	268,500,000	Ethane propane	.....	Oxidation.
	161,500,000	Methane	Water gas	Steam conversion.
Vinyl resins	100,000,000	Butane	Acetylene ethylene	Tubular or regenerative cracking.

[1]Refer to Table 1 for source of data.

Material requirement: The total production of synthetic organic chemicals, by processes as shown, could be produced from the recoverable ethane, propane, butane fractions of 630 billion cu. ft. of natural gas (total gas lost or wasted, 1941) with the accompanying semi-dry gas converted into approximately 55.5 million bbl. of gasoline, diesel, heavy oil mixture via the steam conversion and Fischer Tropsch processes.

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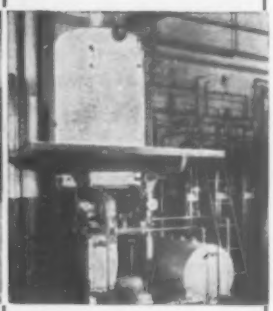

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MAXIM

Preparation of Cyclopentane From An Oklahoma Natural Gasoline*

By J. W. TOOKE, Phillips Petroleum Company

CERTAIN hydrocarbon oils have long been known to contain small amounts of cyclopentane. Brown and Carr[1] in 1926 found an indication of cyclopentane in several gasolines. In 1938 Tongberg, Fenske, and Sweeney[5] cited the presence of cyclopentane in almost all of twenty naphthas investigated by them. They further mentioned the possibility of obtaining fractions (5 or more volume per cent of overall naphtha) of 50 per cent of a particular hydrocarbon by applying efficient fractionation. Cyclopentane was listed as one of the definite possibilities from virgin naphthas. Rossini, Mair, Forziati, Glasgow, and Willingham[4] in 1942 showed the presence of cyclopentane in the paraffin-naphthene portion of an East Texas naphtha as a result of one distillation. Although these investigators and others have recognized the presence of cyclopentane in hydrocarbon oils, no one appears to have reported the actual isolation and testing of the material in high concentration. The purpose of this paper is to report a method for preparing cyclopentane from a natural gasoline.

Appreciable quantities of cyclopentane in natural gasoline produced in the Burbank, Oklahoma, field were first suspected when kettle products from the fractionation of normal pentane from this source were observed to possess unusually low A.P.I. gravities. This was attributed to the presence of a cyclic hydrocarbon and, since it possessed a boiling point between normal *n*-pentane and *n*-hexane, was thought to be cyclopentane. A systematic effort was made to obtain the cyclopentane by precise fractional distillation.

Original stock. A pentane-hexane fraction from natural gasoline was used. The A. S. T. M. distillation and A. P. I. gravity follow:

Initial boiling point	88° F.
5 per cent	96
10 per cent	96
20 per cent	98
30 per cent	99
40 per cent	99
50 per cent	99
60 per cent	100
70 per cent	101
80 per cent	104
90 per cent	113
95 per cent	135
Endpoint	210
°A.P.I.	89.5

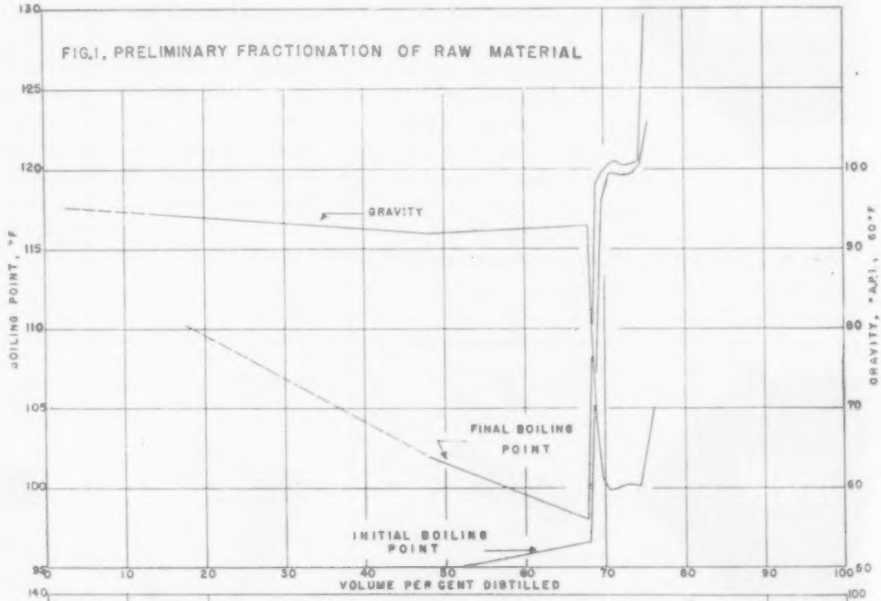
Equipment. The fractionation equipment consisted of two steel batch-type packed columns. The first column or that used for the initial fractionation was 6 in. in diameter and had an overall height of 20 ft. 3 in. It was packed with ½-in. steel Lessing rings for a total depth of 17 ft. 5 in. Reflux was provided by an internal water-cooled coil so that the column operated under partial condensation. Product removal was from the head as a vapor and condensed in a separate water-cooled product condenser. The still had a 250-gal. kettle and was heated by steam.

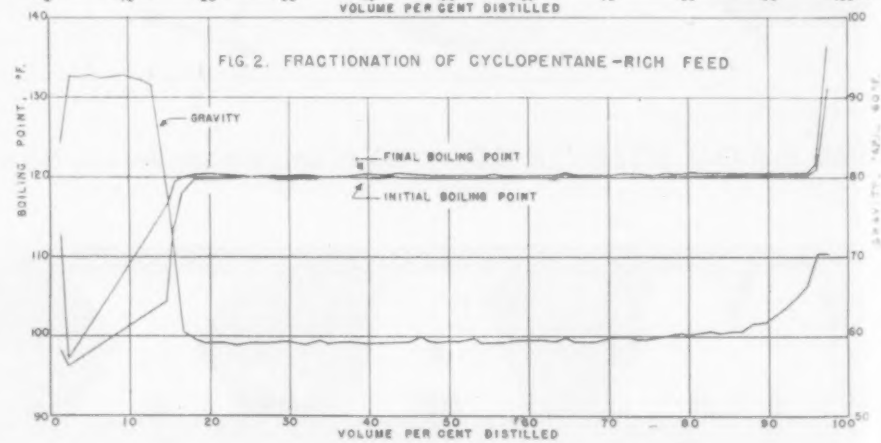
The second column (used for the final fractionation) was 6 in. diameter and had an overall height of 22 ft. 9 in. It was packed with ½-in. stoneware Raschig rings for a total depth of 18 ft. 11 in. The reflux arrangement and vapor take-off assembly were the same as that for the first column. This kettle had a 100-gal. capacity and was also heated by steam.

Procedure. For the preliminary fractionation the still was operated at an average pressure of 47 lb. per sq. in. gauge, a vapor temperature of 181° F., and a kettle temperature of 205° F.

The original stock was charged in 6 batches of approximately 225 gal. each for a total charge of 1350 gal. For each batch the still was brought up to temperature and allowed to come to equilibrium under total reflux. When this had been accomplished, vapor was removed from the head of the column and condensed at the rate of about 5 lb. per hr. and a reflux ratio of about 25 to 1 until nearly all the *n*-pentane had been removed. At this point the vapor removal rate was reduced to 2 lb. per hr. at a reflux ratio of about 50 to 1. Fractionation was continued until all the material boiling between 110° and 130° F. had been taken overhead. The fractions of the distillate boiling below 110° and above 130° F. were discarded.

From time to time during the fractionation, samples of the distillate were examined for A. P. I. gravity and boiling range. Boiling points and ranges were determined by a modified Cottrell boiling apparatus as developed by Quiggle, Tongberg, and Fenske[3]. A typical boiling range-gravity curve showing concentration of the cyclopentane is given in Fig. 1. All boiling points and ranges were obtained under controlled





*Presented before American Chemical Society, Buffalo, New York, meeting.

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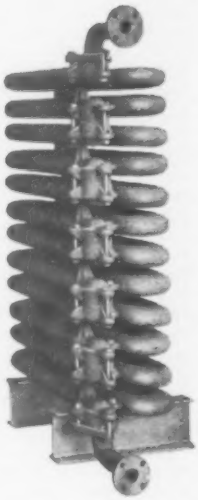
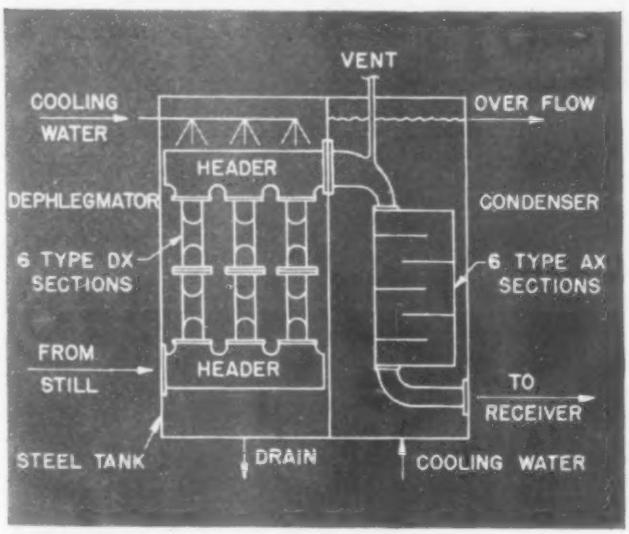
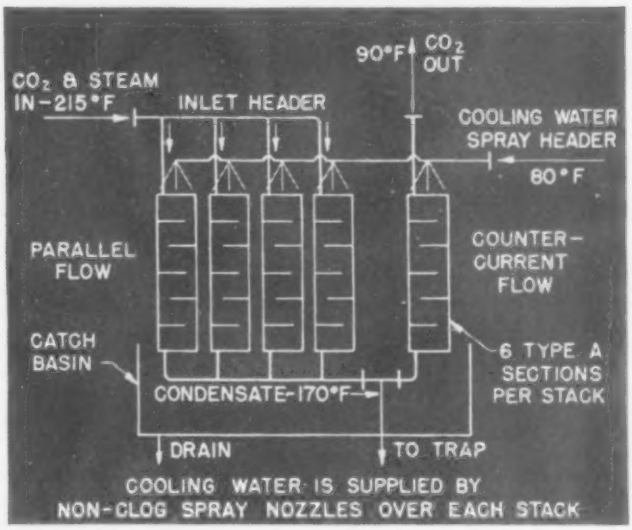


National Sections are cast in a high quality, high strength closed grained grey iron. The type shown is tested hydrostatically at 1000 lbs./sq. in. pressure. Cast Iron chaplets insure immunity from corrosion due to "battery action."

CO_2 COOLER—STEAM CONDENSER

Manufacturers of CO_2 are faced with the problem of removing steam from CO_2 and at the same time cooling the gas. Wet CO_2 is corrosive to many metals but cast iron handles it very well. The two stage condenser-cooler pictured at the right was so successful that two additional units were ordered within the same year.





PYRIDINE DEPHLEGMATOR—CONDENSER

War demand for sulfapyridine called for increased output from coal by-products. The National Section unit shown proved very successful in increasing capacity and reducing maintenance. Temperature in the dephlegmator at the left is controlled by volume of water spray while complete condensation of the pyridine is obtained in the submerged unit on the right.

•

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pressure of 760 mm. of mercury with a certified mercury thermometer. Stem corrections were also applied.

From the six preliminary fractionations, 108 gal. of cyclopentane concentrate were accumulated. A sample of this had an initial boiling point of 116° F., a dry point of 125.7° F., and an A. P. I. gravity of 65.8. This material was charged to the second still for final fractionation. The still was brought to temperature and refluxed until equilibrium was established. During this final fractionation the still was operated at 40 lb. per sq. in. gauge, with a vapor temperature of 201° and a kettle temperature of 204° F. Vapor removal from the head of the column was then started and continued at the rate of about 1.8 lb. per hr. at a reflux ratio of 115 to 1. Condensate was collected in one-gallon cuts, and for each cut the boiling range and A. P. I. gravity were determined. Results are in Fig. 2.

Results

Fig. 2 shows that a long plateau occurred between 19 and 69 per cent distilled with only slight fluctuations in gravity and boiling point. Twice during the distillation the column flooded and was shut down until equilibrium was again established. After 69 per cent distilled, the gravity curve showed a definite though slight rise which continued until the end of the distillation. Fig. 2 shows that, although good fractionation was obtained, the gravity never reached the value for pure cyclopentane, 57.1° A. P. I. (d_4^{20} 0.7460). This is attributed to the presence of a paraffin hydrocarbon which is thought to be neohexane.

Forty-four 1-gal. cuts were selected from near the middle of the plateau and composited for further work. The characteristics of this composite are given in the following table, together with values for the "best sample" from the fractionation and those obtained from the literature for pure cyclopentane.

	This work — Composite	This work — Best sample	Literature (2)
Boiling point (760 mm. Hg), ° C.	49.1	49.1	49.3
Specific gravity, d_4^{20}	0.7363	0.7394	0.7460
Refractive index, n_D^{20}	1.4032	1.4050	1.4068

Assuming the contaminant to be neohexane only, the composite is estimated to contain 91 per cent cyclopentane and the best sample to contain about 95 per cent cyclopentane. Part of this composite sample was used to obtain antiknock characteristics.

The cyclopentane content of the original stock is estimated to be 5.7 liquid volume per cent, equivalent to 2.4 liquid volume per cent of a 12-lb. Reid vapor pressure natural gasoline from a Burbank source.

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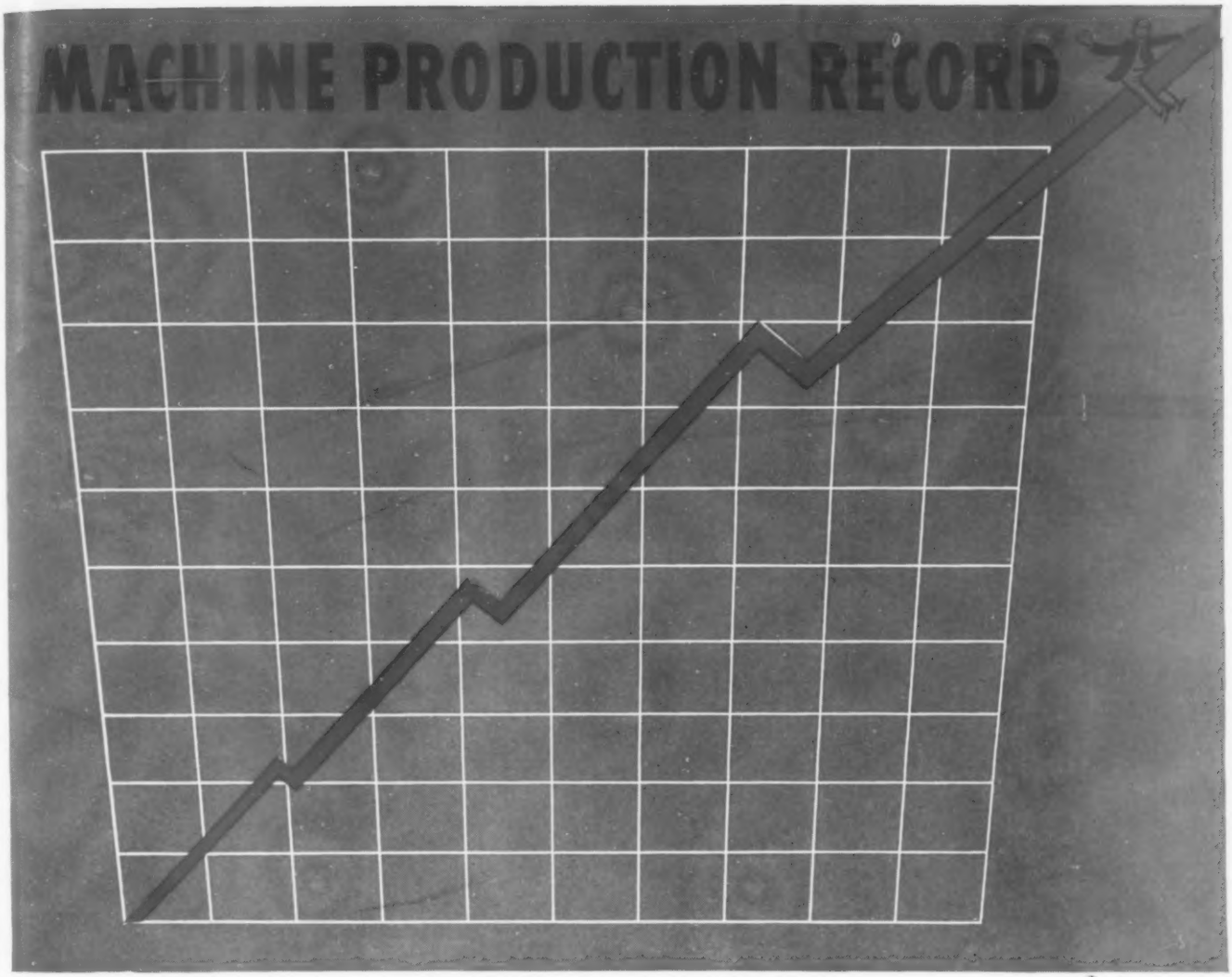

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